PACIFICORP
Rocky Mountain Power
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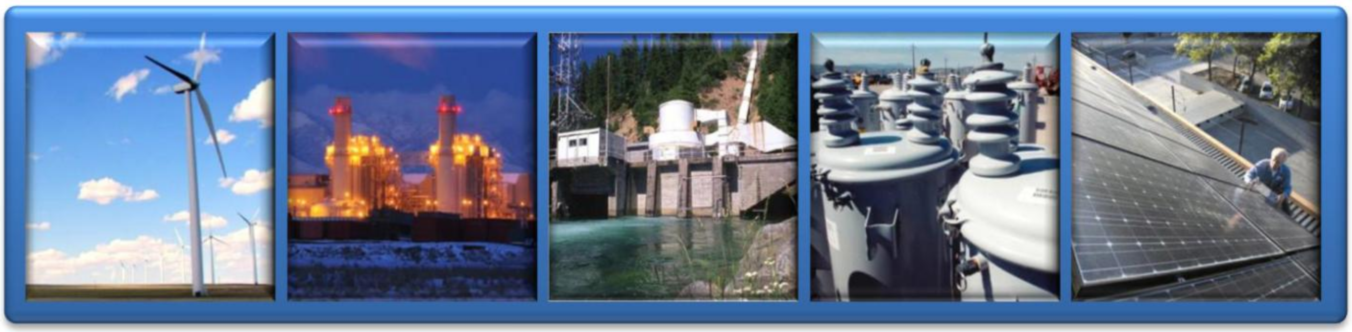
2011
Integrated Resource Plan
Volume II - Appendices



Let's turn the answers on.

March 31, 2011

This 2011 Integrated Resource Plan (IRP) 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 (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
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Transmission: *Distribution Transformers*
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APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used during the 2011 Integrated Resource Plan and scenario development for case sensitivities to varying levels in the load forecast. The load forecasting review starts with the final system level retail sales forecast reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio. The next section elaborates the methodology for long-range load forecasting and provides an overview of the modeling involved. For the state level summaries, retail sales at the customer meter are discussed at the state-level reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio. Finally, the system level and state level load forecast at the generation as used in the 2011 IRP modeling are discussed.

Load Forecast

Table A.1 shows the final retail sales values at the customer meter for the total system as well as individual state level after the load reduction impacts of Class 2 DSM programs included in the 2011 IRP preferred portfolio.

Table A.1 – System Annual Sales forecast (in Gigawatt-hours) 2011 through 2020

System Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	16,272	16,949	20,469	1,285	141	436	**55,553**
2012	16,522	17,699	20,688	1,301	141	437	**56,789**
2013	16,454	18,004	21,524	1,302	141	436	**57,861**
2014	16,567	18,247	22,233	1,302	141	436	**58,927**
2015	16,715	18,529	22,629	1,302	141	436	**59,752**
2016	16,896	18,973	23,050	1,302	142	437	**60,801**
2017	16,953	19,190	23,250	1,302	141	436	**61,273**
2018	17,078	19,452	23,553	1,302	141	436	**61,963**
2019	17,215	19,723	23,842	1,302	141	436	**62,660**
2020	17,335	20,036	24,202	1,303	142	437	**63,454**
Average Annual Growth Rate							
2011-20	**0.7%**	**1.9%**	**1.9%**	**0.2%**	**0.1%**	**0.0%**	**1.5%**

Methodology Overview

PacifiCorp estimates total load by starting with customer class sales forecasts in each state and then adds line losses to the customer class forecasts to determine the total load required at the generators to meet customer demands. Forecasts are based on statistical and econometric modeling techniques and customer-specific sales forecast for large customers. These models incorporate the county and state level forecasts that are provided by public agencies or purchased from commercial econometric forecasting services.

The 2010 load forecast was used for the development of the load and resource balance and portfolio evaluations. Portfolio analysis started in November 2010 with preliminary load forecast and continued through December 2010.

In 2008, to improve sales and load forecasting methods, capabilities, and accuracy, several improvements in the load forecasting approach were identified jointly by the Company and the Company's consultant, ITRON (a firm specializing in load forecasting software and services), and the load forecast methodology was changed to incorporate some improvements. The major assumption changes driving the forecast improvements were discussed in detail in 2008 IRP. Those assumptions were revisited and updated as a part of routine forecast development in this IRP. First, load research data was updated to include six years (2004 -2009) of daily data. This data is used to model the impact of weather on monthly retail sales and peaks by state by class. The Company collects hourly load data from a sample of customers for each class in each state. These data are primarily used for rate design, but they also provide an opportunity to better understand usage patterns, particularly as they relate to changes in temperature. The greater frequency and data points associated with this daily data make it better suited to capture load changes driven by changes in temperature.

Second, in 2008, the time period used to define normal weather was updated from the National Oceanic and Atmospheric Administration's 30-year period of 1971-2000 to a 20-year time period – the latest forecast is based on 1990-2009 as the 20 year time period. The Company identified a trend of increasing summer and winter temperatures in the Company's service territory that was not being captured in the thirty year data. ITRON surveys have identified that many other utilities are also using more recent data for determining normal temperatures. Based on this review and on the recommendation from ITRON, the Company adopted a 20-year rolling average as the basis for determining normal temperatures. This better captures the trend of increasing temperatures observed in both summer and winter.

Third, The Company updated the economic forecasts from IHS Global Insight using the most recent information available for each of the Company's jurisdictions.

Fourth, the historical data period used to develop the monthly retail sales forecasts was updated to cover January 1997 through July 2010 for all classes except for industrial class which goes back to January 2002. The Company updated the forecast of individual industrial customer usage based on the best information available as of August 2010.

Fifth, monthly jurisdictional peaks were forecasted for each state using a peak model and estimated with historical data from 1990-2009. As discussed in the 2008 IRP, as an improvement to the forecasting process, the Company developed a model that relates peak loads to the weather that generated the peaks. This model allows the Company to better predict monthly and seasonal peaks. The peak model is discussed in greater detail in the following section.

Sixth, system line losses were updated to reflect actual losses for the 5-years ending December 31, 2009. Prior to 2008, the Company relied on periodic line loss studies. The Company observed that actual losses were higher than those from the previous line loss study. The use of actual losses is a reasonable basis for capturing total system losses and has been incorporated in this forecast.

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 capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM. System Optimizer 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 System Optimizer, determines the cost-effective mix of Class 2 DSM for a given scenario. For retail load forecast reporting, PacifiCorp develops a load forecast reflecting the chosen Class 2 DSM efficiencies from the 2011 IRP preferred portfolio.

Modeling overview

This section describes the modeling techniques used to develop the load forecast.

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential, commercial, irrigation, public street lighting, and sales to public authority sales forecasts by jurisdiction is developed as a use per customer times the forecasted number of customers.

The customer forecasts are generally based on a combination of regression analysis and exponential smoothing techniques using historical data from January 1997 to July 2010. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of each state's number of households as the major driver. For the commercial class, the Company develops the forecast for number of customers with the forecasted residential customer numbers used as the major driver. For irrigation and street lighting classes, the forecast of number of customers is fairly static and developed using regression models without any economic drivers.

The residential use-per-customer is forecasted by statistical end-use forecasting techniques. This approach incorporates end use information (saturation forecasts and efficiency forecasts) but is estimated using monthly billing data. Saturation trends are based on analysis of the Company's saturation survey data and efficiency trends are based on EIA forecasts that incorporate market forces as well as changes in appliance and equipment efficiency standards. Major drivers of the statistical end use based residential model are weather-related variables, end-use information such as equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The company updated the residential use-per-customer-per-day model with appliance saturation and efficiency results released in June 2009. The SAE models also reflect impacts associated with the Energy Independence and Security Act of 2007, which mandates stricter efficiency standards for incandescent bulbs beginning in 2012.

The commercial, irrigation, street lighting, and sales to public authority use-per-customer forecast is developed using an econometric model. For the commercial class, the Company forecasts sales per customer using regression analysis techniques with employment used as the major economic driver in addition to weather-related variables. For other classes, the Company forecasts sales per customer through regression analysis techniques using time trend variables.

The sales forecast for the residential, commercial and irrigation classes is the product of the number of customer forecast and the use-per-customer forecast. However, 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 Customer Account Managers (“CAMs”). Although the scale is much smaller, the treatment of large commercial additions is similar to the methodology for industrial sales which is discussed below.

Monthly sales for lighting and public authority are forecasted directly for the class, instead of the product of the use-per-customer and number of customers. The forecast is developed by class because the customer sizes in these two classes are more diverse.

The industrial sales forecast is developed for each jurisdiction using a model which is dependent on input for the Customer Account Managers (CAMs). The industrial customers are separated into three categories: existing customers that are tracked by the CAMs, new large customers or expansions by existing large customers, and industrial customers that are not tracked by the CAMs. Customers are tracked by the CAMs if (1) they have a peak load of five MW or more or if (2) they have a peak load of one MW or more and have a history of large variations in their monthly usage. The forecast for the first two categories is developed through the data gathered by the CAM assigned to each customer. The account managers have ongoing direct contact with large customers and are in the best position to know about the customer’s plans for changes in business processes, which might impact their energy consumption.

The Company develops the total industrial sales forecast by aggregating the forecast for the three industrial customer categories. The portion of the industrial forecast related to new large customers and expansion by existing large customers is developed based on direct input of the customers, forecasted load factors, and the probability of the project occurrence. Projected loads associated with new customers or expansions of existing large customers are categorized into three groups. Tier 1 customers are those with a signed master electric service agreement (“MESA”) and Tier 2 customers are those with a signed engineering material and procurement agreement (“EMPA”). When a customer signs a MESA or EMPA, this contractually commits the Company to provide services under the terms of agreement. Tier 3 includes customers with a signed engineering services agreement (ESA). This means that customer paid the Company to perform a study that determines what improvements the Company will need to make to serve the requested load. Tier 4 consists of customers who made inquiries but have not signed a formal agreement. Projected loads from customers in each of these tiers are assigned probabilities depending on project-specific information received from the customer.

Smaller industrial customers are more homogeneous and are modeled using regression analysis with trend and economic variables. Manufacturing employment serves as the major economic driver. The total industrial sales forecast is developed by aggregating the forecast for the three industrial customer categories.

The segments are forecasted differently within the industrial class because of the diverse makeup of the customers within the class. In the industrial class, there is no "typical" customer. Large customers have very diverse usage patterns and power requirements. It is not unusual for the entire class to be strongly influenced by the behavior of one customer or a small group of customers. In contrast, customer classes that are made up of mostly smaller, homogeneous customers are best forecasted as a use per customer multiplied by number of customers. Those customer classes are generally composed of many smaller customers that have similar behaviors and usage patterns. No small group of customers, or single customer, influences the movement of the entire class. This difference requires the different processes for forecasting.

After monthly energy by customer class is developed, hourly loads are estimated in two steps. First, PacifiCorp derives monthly and seasonal peak forecasts for each state. The monthly peak model uses historic peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables which drive heating and cooling usage. These weather variables include the average temperature on the peak day and average daily temperatures for two days prior to the peak day. The peak forecast is based on average monthly historical peak-producing weather for the period 1990-2009.

Second, hourly load forecasts for each state are obtained from the hourly load models using state-specific hourly load data and daily weather variables. Hourly load forecasts are developed using a model that incorporates the 20-year average temperatures, the actual weather pattern for a year, and day-type variables such as weekends and holidays. The model incorporates both mild and extreme days in weather patterns by mapping the normal temperatures to an actual weather pattern. This method effectively represents the daily volatility in weather experienced during a typical year. Also, the method preserves the extreme temperatures and maps them to a year to produce a more accurate estimate of daily temperatures. The hourly load forecasts are adjusted for line losses and calibrated to monthly and seasonal peaks. After PacifiCorp develops the hourly load forecasts for each state, hourly loads are aggregated to the total Company system level. System coincident peaks are then identified as well as the contribution of each jurisdiction to those monthly system peaks.

Sales Forecast at the Customer Meter

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter. The factors influencing the forecasted sales growth rates also influence the forecasted peak demand growth rates.

State Summaries

Oregon

Table A.2 summarizes Oregon state forecasted retail sales growth by customer class.

Table A.2 – Forecasted Sales Growth in Oregon

Oregon Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	5,624	5,142	2,298	266	38	0	**13,368**
2012	5,672	5,399	2,324	282	38	0	**13,715**
2013	5,573	5,490	2,367	283	38	0	**13,750**
2014	5,563	5,526	2,368	283	38	0	**13,778**
2015	5,570	5,557	2,355	283	38	0	**13,803**
2016	5,612	5,603	2,350	283	38	0	**13,886**
2017	5,610	5,616	2,325	283	38	0	**13,872**
2018	5,641	5,647	2,310	283	38	0	**13,920**
2019	5,675	5,677	2,299	283	38	0	**13,971**
2020	5,705	5,720	2,297	283	38	0	**14,043**
Average Annual Growth Rate							
2011-20	**0.2%**	**1.2%**	**(0.0)%**	**0.7%**	**0.0%**	**-**	**0.5%**

The forecast of residential sales is expected to grow at a relatively slower rate of 0.2% annually compared to average annual growth rate of around 1.3% experienced in the past ten years. This slow down is mainly attributed to housing market deterioration worsening economic conditions in the service territory. Beyond2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

Over the forecast horizon, forecasted commercial class sales are projected to grow annually at 1.2%, and are higher than the ten year average annual growth rate in history. Annual growth rate is much higher in the near term as a result of new data centers in the service territory. Usage per customer is projected to decline slightly due to increased equipment efficiency.

As an aftermath of housing market slowdown and economic recession affecting wood products and semi-conductor manufacturing, forecasted industrial class sales are projected to grow at a very slow rate in the forecast horizon. Continued diversification in the manufacturing base in the state and good export opportunities may continue to add to some positive growth in the area.

Washington

Table A.2 summarizes Washington state forecasted retail sales growth by customer class.

Table A.3 – Forecasted Sales Growth in Washington

Washington Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	1,639	1,445	843	160	10	0	**4,097**
2012	1,652	1,471	858	160	10	0	**4,150**
2013	1,636	1,481	865	160	10	0	**4,151**
2014	1,638	1,487	866	160	10	0	**4,161**
2015	1,645	1,493	866	160	10	0	**4,174**
2016	1,662	1,503	868	160	10	0	**4,203**

Washington Retail Sales – Gigawatt-hours (GWh)							
2017	1,665	1,504	865	160	10	0	**4,204**
2018	1,676	1,508	864	160	10	0	**4,217**
2019	1,686	1,510	863	160	10	0	**4,229**
2020	1,696	1,515	864	160	10	0	**4,245**
Average Annual Growth Rate							
2011-20	**0.4%**	**0.5%**	**0.3%**	**0.0%**	**0.0%**	**-**	**0.4%**

The forecast of residential sales is expected to grow at a slower average annual growth rate of 0.4% compared to ten year historical growth rates of around 1.4% due to the continuing impact of housing market slowdown and economic recession. The slight growth in residential class sales is due to continuing customer growth driven by population growth and household formation in the service area. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

Over the forecast horizon, forecasted commercial class sales are projected to grow at an average annual rate of 0.5% due to the aftermath of economic recession.

The industrial class sales are projected to grow at an average annual growth rate of 0.3% reflecting slow recovery in wood products and food processing sectors.

California

Table A.4 summarizes California state forecasted sales growth by customer class.

Table A.4 – Forecasted Retail Sales Growth in California

California Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	398	288	40	98	2	0	**827**
2012	402	290	44	98	2	0	**836**
2013	398	294	45	98	2	0	**837**
2014	399	297	44	98	2	0	**840**
2015	401	297	43	98	2	0	**842**
2016	405	298	42	98	2	0	**846**
2017	405	298	41	98	2	0	**845**
2018	407	299	40	98	2	0	**847**
2019	409	300	39	98	2	0	**849**
2020	411	302	38	98	2	0	**851**
Average Annual Growth Rate							
2011-20	**0.3%**	**0.5%**	**(0.6)%**	**0.0%**	**0.0%**	**-**	**0.3%**

The residential sales are expected to grow at an average annual rate of 0.3%. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The continuing population growth also affects sales in the commercial sector through continued commercial customer growth. However, some of this growth is being offset from increased equipment efficiency over the forecast horizon.

Declines over the decade in the lumber and wood product industries production resulted in an overall decline in the industrial sales for the past two years, and is still facing hardship.

Utah

Table A.5 summarizes Utah state forecasted sales growth by customer class.

Table A.5 – Forecasted Retail Sales Growth in Utah

Utah Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	6,776	8,104	8,377	188	77	436	**23,958**
2012	6,908	8,508	8,221	187	77	437	**24,339**
2013	6,943	8,655	8,594	187	77	436	**24,893**
2014	7,023	8,804	8,873	187	77	436	**25,401**
2015	7,120	9,005	8,978	187	77	436	**25,803**
2016	7,206	9,346	9,114	187	77	437	**26,368**
2017	7,245	9,520	9,185	187	77	436	**26,650**
2018	7,307	9,711	9,299	187	77	436	**27,018**
2019	7,374	9,914	9,395	187	77	436	**27,384**
2020	7,430	10,135	9,513	187	77	437	**27,779**
Average Annual Growth Rate							
2011-20	**1.0%**	**2.5%**	**1.4%**	**(0.0)%**	**0.0%**	**0.0%**	**1.7%**

Utah continues to see natural population growth that is faster than many of the surrounding states. During the historical period, Utah experienced rapid population growth with a high rate of in-migration. However, the rate of population growth is expected to be relatively lower in the coming decade as in-migration into the state slows down relative to history. Over the forecast horizon, residential sales are expected to grow at a slower rate of 1.0% compared to what has been experienced historically in the past ten years due to slower in-migration and slow recovery in housing market in near-term. Beyond 2012, the decline in use per customer is driven by the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The continuing population growth also affects sales in the commercial sector by continued commercial customer growth. Commercial sales are growing at an average annual rate of 2.5% in the forecast horizon mainly due to several data centers starting services in Utah. However some of this growth is being slightly offset from equipment efficiency gains over the forecast horizon.

The industrial class in the state is diversified and will continue to cause sales growth in the sector. Utah has a strategic location in the western half of the United States, which provides easy access into many regional markets. The industrial base has become more linked to the region and is less dependent on the natural resource base within the state. This provides a strong foundation for continued growth into the future. As a result of economic slowdown, over the forecast horizon, industrial sales are growing at a moderate 1.4% as compared to the recent ten year growth rate of 1.6%, but are lower than the pre recession annual average growth rate. As the economy recovers, industrial expansions in a broad range of industries are expected to pick up, and industrial sales are expected to grow again reflecting improvement in overall economic conditions. In 2011, the industrial sales are higher due to a one year load increase by a large industrial customer.

Idaho

Table A.6 summarizes Idaho state forecasted sales growth by customer class.

Table A.6 – Forecasted Retail Sales Growth in Idaho

Idaho Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	732	432	1,665	550	3	0	**3,381**
2012	756	450	1,690	550	3	0	**3,448**
2013	764	467	1,778	550	3	0	**3,562**
2014	784	484	1,883	550	3	0	**3,704**
2015	805	499	1,950	550	3	0	**3,806**
2016	829	512	2,007	550	3	0	**3,901**
2017	846	522	2,016	550	3	0	**3,937**
2018	865	533	2,020	550	3	0	**3,972**
2019	885	544	2,025	550	3	0	**4,007**
2020	905	557	2,033	550	3	0	**4,048**
Average Annual Growth Rate							
2011-20	**0.4%**	**0.5%**	**0.3%**	**0.0%**	**0.0%**	**-**	**0.4%**

Over the forecast horizon, the residential sales are projected to grow at 2.4% annually compared to historical ten year average annual growth rate of 2.8%. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The growth rate for commercial class sales is expected to continue to be strong due to customer growth in response to the increasing residential customer growth resulting in increasing service sector demand such as education and health care services. Usage per customer growth is somewhat offset by equipment efficiency gains over the forecast horizon.

Industrial sales are expected to grow at an average annual rate of 2.2%. This growth is primarily due to expansions by a few large industrial customers.

Wyoming

Table A.7 summarizes Wyoming state forecasted sales growth by customer class.

Table A.7 – Forecasted Retail Sales Growth in Wyoming

Wyoming Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2011	1,103	1,538	7,246	23	12	0	9,921
2012	1,134	1,581	7,552	23	12	0	10,301
2013	1,141	1,617	7,875	23	12	0	10,668
2014	1,159	1,650	8,199	23	12	0	11,043
2015	1,173	1,678	8,437	23	12	0	11,324
2016	1,182	1,710	8,669	24	12	0	11,596
2017	1,181	1,730	8,818	24	12	0	11,765
2018	1,182	1,753	9,019	24	12	0	11,990
2019	1,186	1,778	9,221	24	12	0	12,220
2020	1,188	1,808	9,457	24	12	0	12,489
Average Annual Growth Rate							
2011-20	**0.8%**	**1.8%**	**3.0%**	**0.5%**	**0.0%**	**-**	**2.6%**

Residential sales is expected to grow at an average annual rate of 0.8%, compared to an average annual growth rate of around 2.4% experienced during the past ten years. Population growth is still expected to continue in the service area, which contributes to some of the sales growth. Beyond 2012, use per customer is expected to decline – this decline is mainly due to the impact of long-term lighting efficiency gains resulting from 2007 Federal Energy legislation and other energy efficiency and conservation programs.

Over the forecast horizon, commercial class sales are projected to grow at an annual growth rate of 1.8%. Sales growth is driven mainly by the customer growth in response to still continuing residential customer growth and the growth of the office sector.

Wyoming industrial sales growth, driven by expansion in oil and gas extraction industries, is expected to continue, but at a much reduced rate in the near years due to uncertainty in energy prices. As the economy recovers, industrial growth continues in outer years. Continuing growth in industrial customers in the service area also contributes to the load growth in the residential and commercial customer sectors.

Load Forecast at the Generator

This section provides the load forecast at the generator information used for 2011 IRP portfolio modeling for each state and the system as a whole by year for 2011 through 2020 before Class 2 DSM load reductions are applied.

Energy Forecast

Table A.8 shows average annual energy load growth rates for the PacifiCorp system and individual states. Growth rates are shown for the forecast period 2011 through 2020.

Table A.8 – Forecasted Average Annual Energy Growth Rates for Load

Date Range	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011-2020	2.1%	1.4%	1.2%	0.9%	2.4%	2.9%	2.4%	1.7%

The total net control area load forecast used in this IRP reflects PacifiCorp's forecasts of loads growing at an average rate of 2.1% percent annually from year 2011 to 2020. Table A.9 shows the forecasted load for each specific year for each state served by PacifiCorp and the average annual growth (AAG) rate over the entire time period.

Table A.9 – Annual Load forecasted (in Megawatt-hours) 2011 through 2020

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011	63,131,207	14,968,933	4,579,565	954,604	26,106,815	10,611,408	3,721,679	2,188,202
2012	64,958,409	15,487,788	4,676,478	969,067	26,746,468	11,040,464	3,804,258	2,233,885
2013	66,388,259	15,669,033	4,703,107	972,280	27,389,581	11,451,701	3,937,679	2,264,877
2014	68,035,127	15,853,824	4,754,379	982,164	28,151,361	11,883,924	4,106,332	2,303,143
2015	69,442,054	16,038,453	4,809,526	991,175	28,805,998	12,220,507	4,234,971	2,341,424
2016	71,110,972	16,283,652	4,880,687	1,002,320	29,650,389	12,548,966	4,357,547	2,387,412
2017	72,151,300	16,419,176	4,921,944	1,009,109	30,196,791	12,770,304	4,415,978	2,417,998
2018	73,424,134	16,602,014	4,977,007	1,018,716	30,840,594	13,055,537	4,473,968	2,456,298
2019	74,713,621	16,789,205	5,030,425	1,028,331	31,491,637	13,346,735	4,532,675	2,494,611
2020	76,136,508	16,998,651	5,089,930	1,039,248	32,188,156	13,680,764	4,598,606	2,541,153
Average Annual Growth Rate								
2011-20	2.1%	1.4%	1.2%	0.9%	2.4%	2.9%	2.4%	1.7%
2021-30	1.7%	0.9%	0.9%	0.8%	1.9%	2.5%	1.2%	1.4%
2011-30	1.9%	1.1%	1.1%	0.9%	2.1%	2.7%	1.8%	1.5%

Jurisdictional Peak Load Forecast

The economies, industry mix, appliance and equipment adoption rates, and weather patterns are different for each jurisdiction that PacifiCorp serves. Because of these differences the jurisdictional hourly loads have different daily and hourly patterns. In addition, the growth for the jurisdictional peak demands can be different from the growth in the jurisdictional contribution to the system peak demand. As explained in the methodology section, development of the coincident peaks is based on jurisdictional peaks. However, the jurisdictional peak forecast is not directly used in the IRP portfolio development process.

System-Wide Coincident Peak Load Forecast

The system coincident peak load is the maximum load required on the system in any hourly period. Forecasts of the system peak for each month are prepared based on the load forecast produced using the methodologies described above. From these hourly forecasted values, the coincident system peaks and the non-coincident peaks (within each state) during each month are extracted.

Since 2000, the annual system peak has generally occurred in the summer. The summer system peak is a result of several factors. First, the increasing demand for summer space conditioning in the residential and commercial classes and a decreasing demand for electric related space conditioning in the winter contributes to a summer peak. This trend in space conditioning is expected to continue. Second, Utah with a summer peak that is relatively higher than the winter peak has been growing faster than the system. This growth also contributed to a summer peaking system.

Total system load factor is expected to be relatively stable over the 2011 to 2020 time period. There are several factors working in opposite directions, leading to this result. First, the relatively high growth in high load factor industrial sales, particularly in Wyoming, tends to push up the system load factor. Second, as discussed above, the shift in space conditioning tends to push down the system load factor. And, third, advancing lighting efficiency standards, such as those found in the 2007 Energy Independence and Security Act, which begin to take effect in 2012, also tend to push down the system load factor.

Table A.10 – Forecasted Coincidental Peak Load Growth Rates

Average Annual Growth Rate	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011-2020	2.1%	1.4%	1.6%	0.9%	2.4%	2.6%	2.7%	1.6%

PacifiCorp's eastern system peak is expected to continue growing faster than the western system peak, with average annual growth rates of 2.4 percent and 1.4 percent, respectively, over the forecast horizon. The main drivers for the higher coincident peak load growth for the eastern states include the following:

- Customer growth in residential and commercial classes
- New large commercial customers such as data centers
- Increased usage by Industrial class due to addition of new large industrial customers or expansion by existing customers

Table A.11 below shows that for the same time period the total peak is expected to grow by 2.1 percent.

Table A.11 – Forecasted Coincidental Peak Load in Megawatts

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2011	10,449	2,332	775	160	4,840	1,329	679	336
2012	10,716	2,396	813	163	4,935	1,376	691	341
2013	10,960	2,429	802	164	5,074	1,423	721	346
2014	11,252	2,466	817	163	5,231	1,471	750	353
2015	11,501	2,496	830	166	5,354	1,509	787	359
2016	11,740	2,528	843	169	5,474	1,545	817	365
2017	11,960	2,557	855	171	5,602	1,574	831	370
2018	12,194	2,584	893	173	5,726	1,601	842	376
2019	12,378	2,611	880	174	5,845	1,633	854	381
2020	12,607	2,644	894	174	5,975	1,668	864	388
Average Annual Growth Rate								
2011-20	2.1%	1.4%	1.6%	0.9%	2.4%	2.6%	2.7%	1.6%
2021-30	1.7%	0.9%	1.3%	1.0%	2.0%	2.3%	1.4%	1.4%
2011-30	1.9%	1.2%	1.4%	1.0%	2.2%	2.4%	2.0%	1.5%

Alternative Load Forecast Scenarios

The main purpose of the alternative load forecast cases is to determine the resource type and timing impacts resulting from a structural change in the economy. The focus of the load growth scenarios is from 2014 onward. The Company assumes that economic changes begin to significantly impact loads beginning in 2014, the currently planned acquisition date for the next CCCT resource.

The October 2010 forecast was considered to be the baseline (Medium) scenario. For the high and low growth scenarios, assumptions from IHS Global Insight were applied to the economic drivers in the Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon.

Recognizing the volatility associated with oil and gas extraction industries, PacifiCorp applied additional assumptions for Utah and Wyoming industrial classes for the high scenario. For 2014 and 2015, industrial sales were projected based on historic average growth rates for boom years (2003-2008), and for 2016 and beyond, industrial sales were projected based on historic average growth rates for 2000-2008 (time period with one economic boom and one recession). For Oregon, the probability of new loads from data centers is increased, and a steady growth rate based on the historical average is applied for 2014 onwards for the industrial class.

For the low scenario, the Company assumed a reduced probability of data center growth materializing. Also, for Utah and Wyoming, a double dip recession starting with slower 2011 and 2012 growth was assumed, accompanied by a recovery track from the double-dip recession less than complete for the forecast horizon.

For the 1-in-10 year (10% probability) extreme weather scenario, the Company used 1-in-10 year peak weather for winter (January) and summer (July) months for each state. The 1-in-10 year peak weather is defined as the year for which the peak has the chance of occurring once in 10 years.

Figure A.1 shows the comparison of the above scenarios relative to the Medium scenario. Figure A.2 compares the system coincident peak load forecast with those used for the 2008 IRP Update and 2008 IRP.

Figure A.1 – Load Forecast Scenarios for Low, Medium, High and Peak

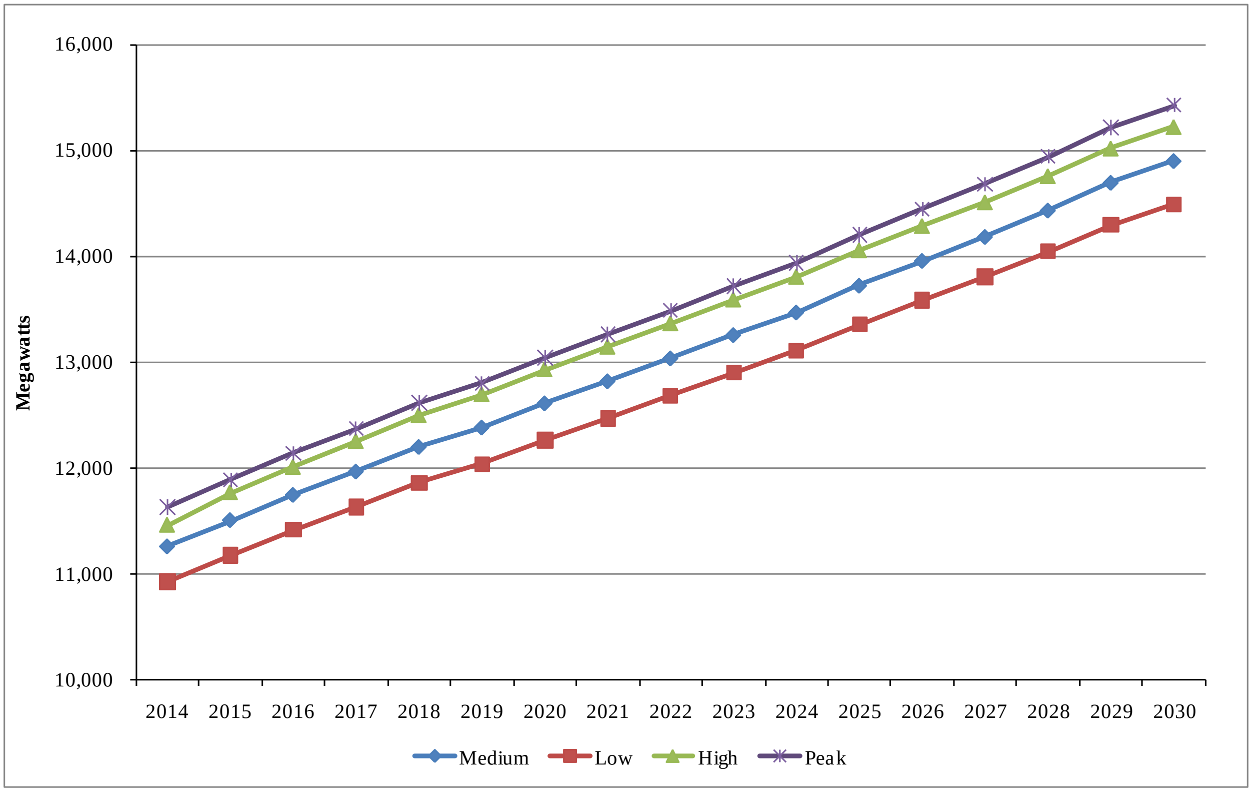
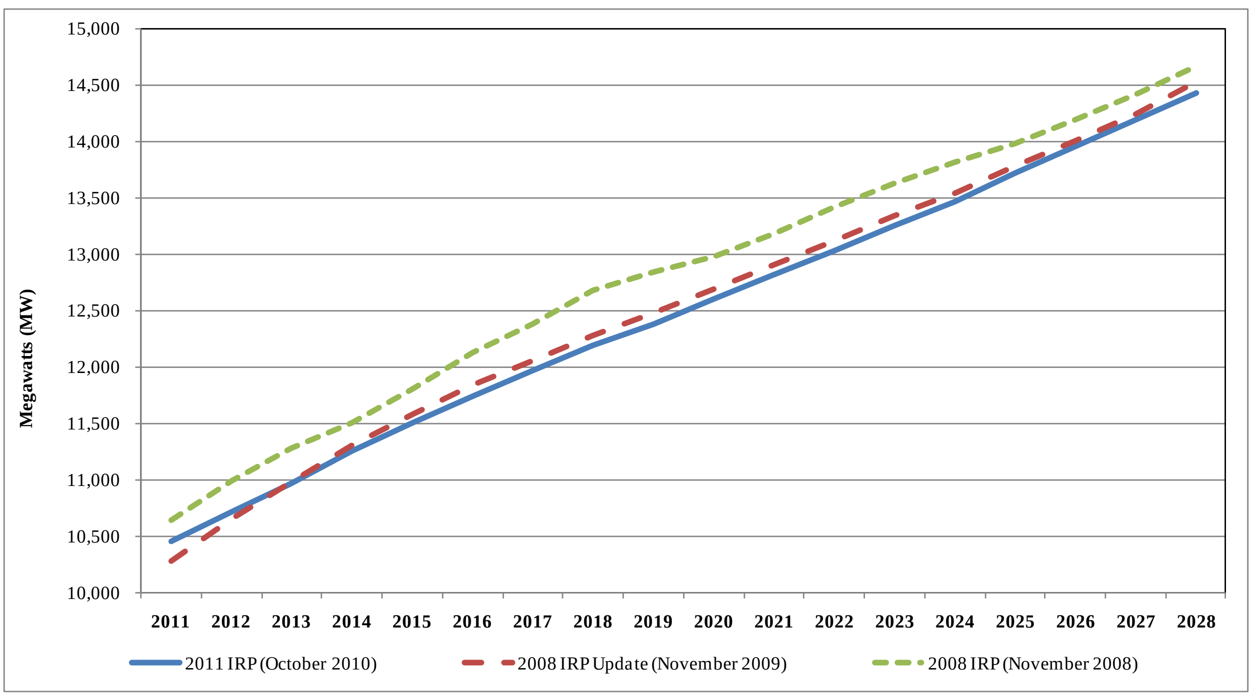


Figure A.2 – Coincident Peak Load Forecast Comparison to Past IRPs



APPENDIX B – IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2011 IRP complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the Company's last IRP ("2008 IRP"), 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.[1]
- Table B.2 – Provides a description of how PacifiCorp addressed the 2008 IRP acknowledgement requirements and other commission directives.
- Table B.3 – Provides an explanation of how this plan addresses each of the items contained in the new Oregon IRP guidelines issued in January 2007.
- Table B.4 – Provides an explanation of how this plan addresses each of the items contained in the Utah Public Service Commission 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 Trade Commission IRP guidelines issued in January 2006.
- Table B.6 – Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with the state commissions. The preparation of the IRP is done in an open public process with consultation between 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, described in Volume 1, Chapter 2, as well as in Appendix F, fully complies with the IRP Standards and Guidelines.

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 loads of PacifiCorp customers and the capability of existing resources to meet this load.

[1] California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP. However, renewable portfolio standard rules require that PacifiCorp file IRP supplements that address how the Company is complying with RPS compliance requirements.

To fill any gap between changes in loads and existing resources, the IRP evaluates all available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 7 and 8 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 Chapter 7.

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 CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 8.

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan (See Chapter 9). 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. Chapter 9 also provides a progress report on action items contained in the 2008 IRP Update Action Plan.

The 2011 IRP and the related Action Plan are filed with each commission with a request for prompt acknowledgement. Acknowledgement means that a commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgement is made. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets acknowledgement standards.

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

California

Subsection (i) of California Public Utilities Code, Section 454.5, states that utilities serving less than 500,000 customers in the state are exempt from filing an Integrated Resource Plan for California. PacifiCorp serves only 45,072 average customers in the most northern parts of the state. PacifiCorp filed for and received an exemption on July 10, 2003.

Idaho

The Idaho Public Utilities Commission's Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. The 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 2007, and fully addresses the above report components. The IRP also evaluates DSM using a load decrement approach, as discussed in Chapters 6 and 7. This approach is consistent with using an avoided cost approach to evaluating DSM as set forth in IPUC Order No. 21249.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its new planning guidelines issued in January 2007 (Order No. 07-002). These guidelines supersede previous ones, and many codify analysis requirements outlined in the Commission's acknowledgement order for PacifiCorp's 2004 IRP.

The Commission's new 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), and resource acquisition (Guideline 13). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgement does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table C.3 provides considerable detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Utah Public Service Commission 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 C.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238), and the rule amendment issued on January 9, 2006 (WAC 480-100-238, Docket No. UE-030311). 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 amendment also now 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 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 Commission on February 21, 2006, and had a follow-up conference call with WUTC staff to make sure the work plan met staff expectations.

Finally, the rule amendment now requires PacifiCorp to provide an assessment of transmission system capability and reliability. This requirement was met in this IRP by modeling the company's current transmission system along with both generation and transmission resource options as part of its resource portfolio analyses. These analyses used such reliability metrics as Loss of Load Probability and Energy Not Served to assess the impacts of different resource combinations on system reliability. The stochastic simulation and risk analysis section of Chapter 7 reports the reliability analysis results.

Wyoming

In 2008, Wyoming proposed draft rule 253 for any utility serving Wyoming to file their Integrated Resource Plan with the commission. The rule went into effect in September 2009.

> ***Rule 253: Integrated Resource Planning***.
> *Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.*

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. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates".	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)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.	Wyoming General Regulations, Chapter 2, Section 253.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation and low-income programs.	Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission.
Frequency	Plans filed biennially, within two years of its previous IRP acknowledgement 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.	File biennially.	RMP to be filed at least biennially. Conservation reports to be filed annually.	The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
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 acknowledgement 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 shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting.
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 OPUC 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 Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. For the amended rules issued in January 2006, PacifiCorp is required 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 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.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
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, and environmental risks, 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.
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). • Identify acquisition	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	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.	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 on January 2009 cover: • Sufficiency of the public comment process • Utility strategic goals and preferred portfolio • Resource need and changes in expected resource acquisitions • Environmental impacts • Market purchase evaluation • Reserve margin analysis • Demand-side management and energy efficiency

Topic	Oregon	Utah	Washington	Idaho	Wyoming
	strategies for action plan resources, assess advantages/disadvantages of resource ownership versus purchases, and identify benchmark resources considered for competitive bidding. • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Avoided cost filing required within 30 days of acknowledgement.	resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders • DSM and supply side resources evaluated at "Total Resource Cost" rather than utility cost.	• Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability (Added per amended rules issued in January 2006). • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using "lowest reasonable cost" criteria. • 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.		

Table B.2 – Handling of 2008 IRP Acknowledgement and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Idaho		
Acceptance of Filing, Case No. PAC-E-09-06, p. 7.	Prior to its next IRP filing, Staff requests that the Company explain and justify why its integration costs have more than doubled. Staff further recommends that the Company perform stochastic modeling to ascertain a value as part of its next IRP.	The Company provided its 2010 wind integration study to IPUC staff in September 2010. This study, included as Appendix I, thoroughly describes the methodology used to derive wind integration cost results. Stochastic modeling is considered impractical given the modeling technology. For example, one key methodology step involved importing unit commitment data from one production cost run into another. This step is not currently possible with multiple stochastic iterations due to the volume of data being processed.
Acceptance of Filing, Case No. PAC-E-09-06, p. 8.	Staff is concerned that the [portfolio performance measure importance weights] were chosen arbitrarily and may ultimately impact the selection of one portfolio over another having equal or greater merit. Staff requests that the Company correct this discrepancy in future planning processes and document the weight deviation in the final plan.	The Company dropped the numerical weighting scheme from the portfolio selection process. See Chapter 7, "Modeling and Portfolio Evaluation Approach".
Acceptance of Filing, Case No. PAC-E-09-06, p. 8.	Staff does not believe that PacifiCorp has adequately quantified the cost associated with meeting an RPS. Staff believes comparing portfolios with and without RPS constraints may facilitate discussions regarding cost allocation and trading rules for renewable energy credits.	PacifiCorp included a portfolio development scenario for which RPS requirements were removed as resource selection constraints (Case #30). Chapter 8 documents the resource and portfolio cost impact of removing RPS requirements (See the section entitled, "Renewable Portfolio Standard Impact".
Acceptance of Filing, Case No. PAC-E-09-06, p. 7.	Staff recommends that the Company conduct sensitivity analyses on the choice of discount rates on resource timing and selection. A standard inflation Treasury bond rate, Staff contends, may serve as a potential lower bound, and the after-tax WACC may serve well as an upper bound.	Due to time constraints for preparation of this IRP, PacifiCorp intends to conduct the recommended sensitivity analysis as part of the 2011 IRP Update, to be filed with the state commissions in 2012.
PURPA QF Wind, ID PAC-E-07-07, p. 6.	Expected wind integration cost information will be included in the Company's integrated resource planning (IRP) process in the same way that costs for other generating resources are included in the IRP.	The wind integration cost information is included in the 2011 IRP as Appendix I. The Company also filed the wind integration study as an attachment to its stipulation commitment compliance filing under Order No. 30497, dated February 14, 2011.
PURPA QF Wind, ID PAC-E-07-07, p. 6.	(PacifiCorp) shall hereafter file notice with the Commission of any changes to its wind integration charge as reflected in subsequent changes to its IRP.	In its stipulation commitment compliance filing under Order No. 30497, the Company did not request a change to the current Commission approved wind integration rate of $6.50/MWh.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
PURPA QF Wind, ID PAC-E-07-07, p. 7.	Idaho wind developers will be notified as part of the public meeting process and can contribute their input at those meetings to discuss PacifiCorp s wind integration study and new data related to wind integration costs prior to the publishing of the Company s next IRP.	PacifiCorp continued to invite Idaho wind developers to IRP public input meetings. Information on the 2010 wind integration study and wind resource modeling in general is posted to the Company's IRP Web site.
Oregon		
Order No. 10-066, Docket No. LC 47, p. 26.	Action Item 3 (Peaking/Intermediate/Base-load Supply-side Resources) - In recognition of the unsettled U.S. economy, expected volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans and regulatory developments. PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP, approved in Docket UM 1360, the next business plan and the 2008 IRP update.	PacifiCorp updated its resource needs assessment and modeling input assumptions as part of the all-source RFP bid evaluation process, 2011 business planning process, and 2011 IRP process. Documentation on these updates was provided as part of the Company's application for approval of its 2008 RFP bidder final shortlist by the Oregon Commission (Docket UM 1360). This IRP also fully documents the comprehensive assumptions update for the 2011 IRP. See Chapter 5, "Resource Needs Assessment", Chapter 7, "Modeling and Portfolio Evaluation Approach", and Appendix A, "Load Forecast Review".
Order No. 10-066, Docket No. LC 47, p. 26.	Additional Action Item 4 - For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.	Energy Gateway financial analysis is included in Chapter 4 of the 2011 IRP. Supporting information is included as Appendix C.
Order No. 10-066, Docket No. LC 47, p. 26.	Additional Action Item 5 - By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.	PacifiCorp completed the wind integration study and distributed it to the public via email and Web site posting on September 1, 2010 in accordance with the Oregon Commission granting a deadline extension from August 1 to September 1, 2010. The study is included in the 2011 IRP as Appendix I.
Order No. 10-066, Docket No. LC 47, p. 26.	Additional Action Item 6 - During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.	Total CO_2 emissions for the 20-year simulation period were included as a final screening performance measure for portfolio evaluation and determination of the 2011 IRP preferred portfolio. See the "Final Screening" section of Chapter 7 and

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
		portfolio evaluation results in Chapter 8, "Modeling and Portfolio Evaluation Results".
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item 7 - In the next IRP, provide information on total CO_2 emissions on a year-to year basis for all portfolios, and specifically, how they compare with the preferred portfolio.	CO_2 emissions trend charts for each portfolio, including the preferred portfolio, are included in Appendix D.
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item 8 - For the next IRP planning cycle, PacifiCorp will work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.	PacifiCorp used portfolio development case number 9 for testing how out-year resource selection (years 2021-2030) impacts selection of near-term resources (years 2011-2020). The Company compared two portfolios: a base 20-year System Optimizer run and a test 20-year run where resources for the first 10 years are fixed based on a prior 10-year simulation. Results are summarized in Chapter 8, "Modeling and Portfolio Evaluation Results".
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item 9 - In the next IRP planning cycle, PacifiCorp will incorporate its assessment of distribution efficiency potential resources for planning purposes.	PacifiCorp is conducting a conservation voltage reduction study, targeting 19 distribution feeders in Washington. The study is expected to be completed by the end of May 2011. Based on preliminary data provided by the contractor for the study, PacifiCorp developed a distribution efficiency resource for testing with the System Optimizer model. Results of the portfolio development testing are provided in Chapter 8, "Modeling and Portfolio Evaluation Results".
Order No. 10-066, Docket No. LC 47, p. 26.	Revised Action Item 9 (Planning Process Improvements) - For the next IRP planning cycle complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions.	PacifiCorp successfully implemented the System Optimizer model enhancements, and defined five emission hard cap evaluation cases for modeling (nos. 15-18, plus a hard cap case for coal plant utilization scenario analysis). PacifiCorp conducted System Optimizer modeling for five coal plant utilization scenarios in which coal units are allowed to be replaced by CCCT resources, taking into account coal plant incremental costs. Modeling results are described in Chapter 8, "Modeling and Portfolio Evaluation Results". As noted in this chapter, the coal utilization study is intended as a modeling proof-of-concept only.
Order No. 10-066, Docket No. LC 47, p. 26.	Revised Action Item 9 (Planning Process Improvements) - In the next IRP planning cycle provide an evaluation of, and continue to investigate, the formulation of satisfactory proxy intermediate-term market purchase resources for purposes of portfolio modeling and contingent on acquiring suitable market data.	PacifiCorp's All-source RFP, reactivated in December 2009, yielded no satisfactory proxy intermediate-term market purchase resources.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Order No. 10-066, Docket No. LC 47, p. 27.	Additional Action Item [not numbered] - In addition, the Company will file its 2008 IRP Update approximately one year after the date of this Order, in compliance with Guideline 3.	The 2011 IRP fulfills the filing requirement, given that the March 31, 2011 filing date is approximately one year after the acknowledgment of the 2008 IRP (February 24, 2010).
Order No. 10-066, Docket No. LC 47, p. 24.	With regard to NWEC's suggestion that appropriate reserves be separately determined, we direct the parties to discuss this issue in the next planning.	PacifiCorp discussed planning reserve margin analysis at its August 4, 2010, public input meeting. The Company outlined a loss of load study to determine an appropriate planning reserve margin to apply for portfolio development. Public stakeholders did not take issue with the study approach. The study was distributed for IRP participant review November 18, 2010.
Utah		
UT Docket No. 09-2035-01, Report & Order, p. 24.	At a minimum, we direct the Company to perform a sensitivity case in its next IRP or IRP update wherein the ENS cost is flat and based on the Federal Energy Regulatory Commission price cap.	This sensitivity analysis is described in the section entitled, "Cost of Energy Not Served (ENS) Sensitivity Analysis" in Chapter 8.
UT Docket No. 09-2035-01, Report & Order, p. 24-25.	Additionally, in an IRP public input meeting, we direct the Company to identify a reasonable number of cases, including high and low load growth cases, to compare the costs and risks to customers, or to identify a reasonable alternative method, e.g., a LOLP study, for evaluating an appropriate planning reserve.	PacifiCorp conducted a stochastic loss of load study for this IRP, which was published November 18, 2010 for review by stakeholders, and is presented as Appendix J. The Company also developed high/low economic growth and 1-in-10 peak-producing temperature scenarios for evaluating portfolio impacts of alternative load forecasts. The results of these alternative load forecasts are described in Chapter 8. Stochastic production cost results are reported in Appendix E.
UT Docket No. 09-2035-01, Report & Order, p. 30.	At a minimum, we direct the Company to include the costs of hedging in its IRP analysis of resources that rely on fuels subject to volatile prices.	PacifiCorp addresses hedging costs in Appendix G, "Hedging Strategy".
UT Docket No. 09-2035-01, Report & Order, p. 30.	We also direct the Company to perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers.	The Company discusses hedging strategies and the impacts of various hedging levels on risk and expected cost in Appendix G, "Hedging Strategy".
UT Docket No. 09-2035-01, Report & Order, p. 30.	Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market.	The Company's analysis of western resource adequacy is provided as Appendix H. Identification of who bears the risk of market reliance (customers versus shareholders) is identified as well.
UT Docket No. 09-2035-01, Report & Order, p. 30.	Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue [WECC market depth and liquidity] in an IRP	Based on feedback from parties attending the June 2010 Utah IRP stakeholder input meeting, PacifiCorp developed a market purchase stress test proposal, which was vetted at the October 5th IRP

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
	public input meeting for inclusion in the next IRP or IRP update.	general public input meeting. The results of the stress test, which used stochastic production cost simulation, are described in Appendix H.
UT Docket No. 09-2035-01, Report & Order, p. 35.	We direct the Company to discuss methods for improving the evaluation of nontraditional resources in an IRP public input meeting. At a minimum, this discussion should include ideas for improving the evaluation of distributed solar technologies which provide opportunities for customer participation, i.e., a solar rooftop customer buy-down program, and options for improving the evaluation of storage technologies designed to enhance the value and performance of intermittent renewable resources.	PacifiCorp discussed the evaluation of nontraditional resources, including energy storage, at the August 4, 2010 IRP public input meeting. A consultant study on incremental capacity value and ancillary service benefits of energy storage is planned for 2011 or 2012. This study is identified in the 2011 IRP action plan.
UT Docket No. 09-2035-01, Report & Order, p. 35.	We also concur with the Division and Office regarding the need for review of geothermal resources and direct the Company to file a geothermal resource study as described by the Division within 60 days of the date of this order. We will initiate a comment period upon its filing and this information can be included in the next IRP or IRP update.	The geothermal resource report was filed with the Utah Commission on August 10, 2010 in accordance with the Commission's deadline extension. A conference call with Utah parties to discuss the report and the Company's follow-up activities was held December 9, 2010.
UT Docket No. 09-2035-01, Report & Order, p. 35.	In the future, the Company is directed to omit from its core cases any resource for which it does not already have a signed final procurement contract or certificate of public convenience and necessity. However, this does not preclude the Company from including such resources in sensitivity cases. This will assist with the consistent and comparable treatment of resources going forward.	No resource has been fixed in the core portfolios, except for the 2011 business plan core case #19, which is intended as a reference case for planned resources identified in the business plan.
UT Docket No. 09-2035-01, Report & Order, p. 38.	... we again direct the Company to address these issues in the next IRP or IRP update: i.e., • Number of years relied upon for developing stochastic parameters. • Role of planning reserve in managing the risks of forecast error.	PacifiCorp discussed stochastic parameter updates at the December 15, 2010 IRP public meeting. Due to time constraints, PacifiCorp targeted its load stochastic parameters for updating in the 2011, using a three-year data set originally prepared for the 2010 wind integration study.
UT Docket No. 09-2035-01, Report & Order, p. 39.	[We] direct the Company and interested parties to examine and consider all of the suggestions contained in [the GDS] report. At a minimum, the Company is directed to provide a range of load forecasts that comport with industry standards as recommended by GDS. Further, as recommended by GDS, we direct the Company to provide the	As noted above, PacifiCorp adopted the GDS recommendations for inclusion of load growth scenarios based on different assumptions concerning economic drivers. The Company also developed a 1-in-10 peak-producing temperature scenario. The results of these alternative load forecasts are described in Chapter 8. Appendix A constitutes the Company’s standalone

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
	Commission with a comprehensive stand-alone load forecast report when the forecast is updated. The GDS suggestions could reduce last minute revisions due to load forecast changes and thereby assist in the timely completion of future IRPs.	load forecast report.
UT Docket No. 09-2035-01, Report & Order, p. 40.	We again direct the Company to address [hydro capacity accounting] in its next IRP or IRP update and provide the results of its analysis. For example, it may be useful to conduct sensitivity analysis regarding this assumption to identify potential risks or shortcomings of the current methodology.	PacifiCorp provided a detailed analysis of 18-hour sustained hydro peaking capability and its applicability to hydro capacity accounting in the load & resource balance in Appendix H.
UT Docket No. 09-2035-01, Report & Order, p. 41.	We concur with the Division and direct the Company to complete its own wind integration study. We understand this process is underway and that the Company is circulating the study for review. We direct the Company to address the Division's concerns and include this study in the next IRP or IRP update.	PacifiCorp completed the wind integration study and distributed it to the public via email and Web site posting on September 1, 2010. The study is included in the 2011 IRP as Appendix I.
UT Docket No. 09-2035-01, Report & Order, p. 42.	[W]e direct the Company to solicit and discuss further improvements to its resource acquisition path analysis and decision mechanism and address the Division's concerns in its next IRP or IRP update.	PacifiCorp expanded the acquisition path analysis to include alternative regulatory policy scenarios, and applied sensitivity analysis results to identify acquisition paths and resource quantities for load growth and natural gas price forecast trends. A more extensive discussion of the decision mechanism has been provided in response to the Utah Division of Public Utilities written comments on the 2008 IRP.
UT Docket No. 09-2035-01, Report & Order, p. 54.	In order to ensure timely and meaningful information exchange, we direct the Company to adopt two of the Division's recommendations on improving public input meetings. • First, materials should be distributed one week prior to the public input meeting. • Secondly, a written report should be provided after each meeting to provide follow-up to issues or questions raised in the meeting.	PacifiCorp has complied with the requirement to distribute meeting materials one week prior to public meetings. Written reports on public meetings have been prepared and distributed to participants via email and postings to the IRP Web site.
UT Docket No. 09-2035-01, Report & Order, p. 55.	We concur with the Division and UAE, training on the Company's models in order for parties to validate the models and to gain confidence in the modeling results is worthwhile. We direct the Company to convene at least a full-day meeting to this end.	PacifiCorp is planning to hold tutorial sessions during the second quarter of 2011 for both System Optimizer and the Planning and Risk model. A non-disclosure agreement between participants and the model vendor, Ventyx, will be required due to sharing of proprietary information.
Utah Commission Docket No. 08-035-56, DSM Potential Study, Report &	The Company proposes to adjust the technical potential using its assumptions regarding achievable levels of DSM to serve as the supply curves in its IRP. It	PacifiCorp ran System Optimizer with DSM supply curves based on unadjusted technical potential. Given the particular input assumptions used, the model deferred CCCT resources. The results of this

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Order, p. 8.	would then use these adjusted supply curves in IRP to determine cost-effective amounts of DSM. UCE and WRA disagree and propose that the Company use the unadjusted technical potential to form the supply curves in IRP to determine the full cost-effective level of DSM and then make provision in its path or contingency analysis for the possibility that the cost-effective amount of DSM may not be achieved in the time-frame modeled...we direct the Company to evaluate the two approaches in its next IRP or IRP update. We encourage the Company to solicit input from interested parties on methods for evaluating the two approaches. We will request parties' comments on the Company's evaluation of the two approaches in an appropriate IRP or IRP update docket.	study are described in Chapter 8, "Demand-side Management Cases."
DSM Potential Study, Docket No. 08-035-56, Report & Order, p. 9.	With respect to estimating the cost of solar resources, UCE and WRA provide considerably different cost estimates than PacifiCorp. The differences are large enough that we would expect significant differences to appear in the Company's IRP action plan depending on the assumptions used in the IRP process. We direct the Company to perform sensitivity analysis with respect to the assumed cost of solar resources in its next IRP or IRP update.	PacifiCorp updated all distributed generation cost estimates for the 2011 IRP, including solar resources. The Cadmus Group prepared input assumptions memos that were distributed to public stakeholders for review and comment in July and August, 2010.
DSM Potential Study, Docket No. 08-035-56, Report & Order, p. 9.	Going forward, the Company shall provide information on both the total cost of solar resources in comparison to other resources, and also the cost to the utility of a utility-sponsored program to encourage customer adoption of this resource. The Company could begin such analysis with preliminary data from the solar incentive pilot program. We direct PacifiCorp to work with interested parties regarding how to evaluate solar resources in the ongoing IRP process and we will consider comments on this effort in an appropriate IRP proceeding.	PacifiCorp discussed with interested parties System Optimizer portfolio development scenarios reflecting a solar PV cost buy-down program. A conference call was held January 27, 2011, to finalize the study approach. The modeling approach is described in the section titled "Case Definitions" in Chapter 7. Modeling results are summarized in the section titled, "Renewable Resource Cases" in Chapter 8.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2011 IRP
Washington		
Letter Order, UE-080826, Attachment p. 1.	Transmission Planning (Chapter 4). The next IRP should discuss alternative transmission options.	Chapter 4 outlines an analysis of seven Energy Gateway deployment scenarios that considers alternative transmission footprints, investment costs, in-service dates, and economic drivers.
Letter Order, UE-080826, Attachment p. 1.	Transmission Planning (Chapter 4). The next IRP should discuss alternative deployment schedules for the transmission projects it considers and the benefits of each of the alternative deployment schedules of any transmission segments considered in the modeling.	Chapter 4 focuses on two deployment scenarios based on alternative directions for state and federal resource policies: a Green Resource Future and Incumbent Resource Future. Additionally, the section entitled “Customer Load and Resources” in Chapter 4 summarizes the process that PacifiCorp follows, in compliance with its Open Access Transmission Tariff, to plan for and invest in transmission to meet network customer load requirements.
	Specifically, the various portfolios have different resource selections during the first five years of the planning period. This might result in PacifiCorp, in its planning process, choosing a set of early resources because they are in a portfolio with lower risks in the later years of the planning horizon, even though the portfolios with higher risks could be mitigated by future flexibility rather than by choosing a different portfolio. • PacifiCorp should address this issue in its next IRP	PacifiCorp conducted a sensitivity analysis to isolate the near-term resource selection impact of out-year resources in the context of capacity expansion optimization modeling. The results of the sensitivity analysis are provided in Chapter 8.
Letter Order, UE-080826, Attachment p. 4.	The action plan does not specifically mention the utility's obligation under RCW 19.285 to determine and meet certain energy efficiency targets. The Commission reminds the Company that it needs to meet this obligation.	Action Item Number 6, Class 2 DSM, explicitly mentions PacifiCorp’s obligation to meet energy efficiency targets under RCW 19.285.
Wyoming		
The Wyoming Public Service Commission provided the following comment in its Letter Order (Docket No. 20000-346-EA-9, dated 11/23/2010) on PacifiCorp’s 2008 IRP: *Pursuant to open meeting action taken on January 11, 2008, PacifiCorp d/b/a Rocky Mountain Power’s 2007 Integrated Resource Plan (IRP) is hereby placed in the Commission’s files. No further action will be taken and this docketed matter is closed.*		

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

No.	Requirement	How the Guideline is Addressed in the 2011 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, distributed generation, energy storage, power purchases, thermal resources, and transmission. Chapters 4 (Transmission Planning), 6 (Resource Options), and 7 (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, System Optimizer, and selected by the model based on 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 System Optimizer 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, life-times, and locations.
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 Cadmus Group's supply curve data developed in 2010 for representation of DSM and distributed generation resources, which was also 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 Chapters 6 and 7.
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 after-tax WACC of 7.17 percent to discount all cost streams.
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.	PacifiCorp fully complies with this requirement. Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation with the exception of CO_2 emission compliance costs, which are treated as a scenario risk. See the stochastic modeling methodology section in Chapter 7.
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	PacifiCorp complied with this guideline by discussing resource risk mitigation in Chapter 9 as well as addressing market reliance risk and hedging strategies in Appendix G and H, respectively. Topics covered include: (1) managing carbon risk for existing plants, (2) the use of physical and

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
		financial hedging for electricity price risk, and (3) managing gas supply risk. Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Chapters 4 and 8.
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 Chapter 8 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 for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects consistent with past IRP practice.
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.	PacifiCorp fully complies. Chapter 7 provides a description of the PVRR methodology.
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 (mean of highest five Monte Carlo iterations) 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 costs and risks of hedging is provided in Appendix G.
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Chapter 8 summarizes the results of PacifiCorp’s cost/risk tradeoff analysis, and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state resource policies. The IRP action plan chapter also presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
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 Commission for resolution.	PacifiCorp fully complies with this requirement. Chapter 2 provides an overview of the public process, while Appendix D documents the details on public meetings held for the 2008 IRP.
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 Commission.	Both IRP volumes provide non-confidential information the company 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.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed a partial draft IRP document for external review on February 23, 2011 and the remaining chapters on March 7, 2011.
Guideline 3: Plan Filing, Review, and Updates		
(3)	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 Commission.	This Plan complies with this requirement.
(4)	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	Not applicable; activity conducted subsequent to filing this IRP.
(5)	Commission staff and parties must complete their comments and recommendations within six months of IRP filing.	Not applicable; activity conducted subsequent to filing this IRP.
(6)	The Commission must consider comments and recommendations on an energy utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the energy utility an opportunity to revise the IRP before issuing an acknowledgment order.	Not applicable; activity conducted subsequent to filing this IRP.
(7)	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; activity conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
(8)	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. The energy utility must summarize the annual update at a Commission public meeting. The energy utility may request acknowledgment of changes, identified in its update, the IRP action plan. The annual update is an informational filing that: (a) Describes what actions the energy utility has taken to implement the action plan to select best portfolio of resources contained in its acknowledged IRP; (b) 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 (c) Justifies any deviations from the action plan contained in its acknowledged IRP.	Not applicable; activity conducted subsequent to filing this IRP.
(9)	As soon as an energy utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the energy utility is within six months of filing its next IRP. This update must meet the requirements set forth in section (8) of this rule.	Not applicable; activity conducted subsequent to filing this IRP.
	If the energy utility requests Commission acknowledgement of its proposed changes to the action plan contained in its acknowledged IRP: (a) The energy utility must file its proposed changes with the Commission and present the results of its proposed changes to the Commission at a public meeting prior to the deadline for written public comment; (b) Commission staff and parties must file any comments and recommendations with the Commission and present such comments and recommendations to the Commission at a public meeting within six months of the energy utility's filing of its request for acknowledgement of proposed changes; (c) The Commission may provide direction to an energy utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable; activity conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 4. Plan Components (at a minimum, must include…)		
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The purpose 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 and high load growth forecasts for scenario analysis based on economic growth assumptions using the System Optimizer model for portfolio development. Stochastic variability of loads was also captured in the risk analysis. See Chapters 5, 7, and 8, as well as Appendix A, for load forecast information. Chapter 8 also describes how loads are handled in the stochastic modeling.
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.	This Plan complies with the requirement. See Chapter 5 for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies, as mentioned in Chapter 7.
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	Chapter 6 identifies the resources included in this IRP, and provides their detailed cost and performance attributes. See Tables 6.2 through 6.10 for supply-side resources, and Tables 6.15 through 6.20 for demand-side resources.
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, the company used several measures to evaluate relative portfolio supply reliability. These are described in Chapter 7 (Energy Not Served and Loss of Load Probability). PacifiCorp conducted a stochastic loss of load study in 2010 to support selection of the planning reserve margin. This study is included as Appendix J.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	Chapter 7 describes the key assumptions and alternative scenarios used in this 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 Plan documents the development and results of 67 portfolios designed to determine resource selection under a variety of input assumptions (Chapter 8).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Chapter 8 and Appendix E present 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.	Chapter 8 provides tables and charts with performance measure results, including rank ordering.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	PacifiCorp fully complies with this guideline. See the responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is presumed to have no inconsistencies.
	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.	Chapters 9 and 10 presents the 2011 IRP and transmission expansion action plans, respectively.
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 proxy transmission resources on a comparable basis with respect to other proxy resources in this IRP. 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.	A multi-state demand-side management potentials study was completed in late 2010, and those results were incorporated into this plan.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Chapter 6.
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.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
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 3 DSM) on a consistent basis with other resources in a portfolio sensitivity study. Class 3 DSM programs are addressed in Item 7 of the IRP action plan in Chapter 9.
Guideline 8: Environmental Costs		
8	a. Base Case and Other Compliance Scenarios b. Testing Alternative Portfolios Against the Compliance Scenarios c. Trigger Point Analysis d. Oregon Compliance Portfolio	This IRP fully complies with the CO_2 compliance cost analysis requirements in Order No. 08-339. Performance results for CO_2 compliance scenario portfolios are reported in Chapter 8, including hard cap scenarios using the Oregon emission targets in HB 3543.
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.	PacifiCorp continues to plan for load for direct access 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 2011 IRP conforms to the multi-state planning approach as stated in Chapter 2 ("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.	PacifiCorp fully complies with this guideline. See the response to 1.c.3.1 above. Chapter 8 describes 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. (Chapter 8).
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 evaluated several types of distribution generation, including combined heat and power and solar. The results of these evaluations are documented in Chapter 8.

No.	Requirement	How the Guideline is Addressed in the 2011 IRP
Guideline 13: Resource Acquisition		
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	Chapter 9 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 9. Company resources included in RFPs is addressed in the action plan (Table 9.1 and accompanying narrative).
13.b	For gas utilities only	Not applicable

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

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Utah Public Service Commission 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 IRP process.
3	Prudence Reviews of new resource acquisitions will occur during ratemaking proceedings.	Not addressed; ratemaking occurs outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix D.
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 Chapter 7 for a description of the methodology employed, including how CO_2 cost uncertainty is factored into the determination of relative portfolio performance.
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 the Utah rules, PacifiCorp determination of avoided costs will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
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.	Chapter 9 describes the linkage between the 2011 IRP preferred portfolio and 2011 business plan resources approved in December 2010. Significant resource differences are highlighted.
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.	Chapter 7 outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 8 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 May 28, 2009, and filed this IRP on March 31, 2011. PacifiCorp files the IRP with all commissions on March 31 in each odd-numbered year.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Chapter 2. A record of public meetings is provided as Appendix F.
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 2011 IRP are provided in Appendix A. Figure 7.4 in Chapter 7 shows the range of forecasts used for capacity expansion modeling. Figures 7.18 through 7.24 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
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	Price risk associated with market sales is captured in the company's stochastic simulation results. Current off-system sales agreements are included in the IRP models.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
	some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Appendix A documents how demographic and price factors are used in PacifiCorp's new load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model.
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 Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Chapter 6. A sensitivity study of demand-response programs (Class 3 DSM) was also conducted (See Chapter 8).
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 segments. Chapters 4, 6 and 7 document how 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 and distributed generation resources used for portfolio modeling explicitly incorporate estimated rates of program and event participation. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.
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 Chapter 9.
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2011-2030)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Chapter 9. A status report of the actions outlined in the previous action plan (2008 IRP update) is provided in Chapter 9 as well. The action plan (Table 9.1) also identifies actions anticipated to extend beyond the next two years, or occur after the next two years

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 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.	Chapter 9 includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, combinations of load growth and gas price futures, and procurement delays. The associated decision mechanism is also described in more detail relative to the 2008 IRP.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Chapter 7. The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Portfolios were evaluated using a range of CO_2 cost futures. ● A discussion of environmental policy status and impacts on utility resource planning is provided in Chapter 3. ● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Chapter 8. ● Appendix L reports historical water consumption for PacifiCorp's thermal plants.
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Chapter 9, and covers managing carbon risk for existing plants and managing gas supply risk. Transmission expansion risks are discussed in Chapter 3. Appendix G discusses hedging. Appendix H discusses market reliance risks and identifies who bears associated risks. Resource capital cost uncertainty and technological risk is addressed in Chapter 6 ("Handling of Technology Improvement Trends and Cost Uncertainty"). 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 Chapter 9.
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Chapter 9 and the action plan (Table 9.1).
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. This trade-off analysis is documented in Chapter 8, and highlighted through the use of scatter-plot graphs showing the relationship between stochastic mean and upper-tail mean stochastic PVRR.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
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 CO_2, NO_X, SO_2, and mercury with use of cost adders and assumptions regarding the form of compliance strategy (for example, a per-ton tax and hard emissions caps for CO_2). For CO_2 externality costs, the company used scenarios with various cost levels to capture a reasonable range of cost impacts. These cost assumptions are described in Chapter 7.
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.	The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Chapter 6.
5	PacifiCorp will submit its IRP for public comment, review and acknowledgement.	PacifiCorp distributed a partially completed draft IRP document for public review and comment on February 23, 2011, and the complete draft IRP document (Volume 1) on March 7, 2011.
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 acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgement 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 (WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the IRP work plan on March 31, 2010, given an anticipated IRP filing date of March 31, 2011.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 2-5 of the Work Plan document for a summarization of resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See pages 6-7 of the Work Plan. Figure 2, page 6, document for the IRP schedule.
(4)	Integrated resource plan submitted within two years of previous plan.	The Commission issued an Order on December 11, 2008, under Docket no. UE-070117, granting the Company permission to file its IRP on March 31 of each odd numbered year. PacifiCorp filed the 2011 IRP on March 31, 2011.
(5)	Commission issues notice of public hearing after company files plan for review.	Not applicable; activity conducted subsequent to filing this IRP.
(5)	Commission holds public hearing.	Not applicable; activity conducted subsequent to filing this IRP.
(2)(a)	Plan describes the mix of energy supply resources.	Chapter 5 describes the mix of existing resources, while Chapter 8 describes the 2011 IRP preferred portfolio. For example, see Tables 8.16 and 8.17, as well as Figures 8.11 and 8.12.
(2)(a)	Plan describes conservation supply.	See Chapter 8 for a description of how conservation supplies are represented and modeled. Refer to Tables 8.16 and 8.17, as well as Figures 8.11 and 8.12. The 2010 resource potential study upon which conservation supplies are based is available from PacifiCorp's demand-side management Web site, http://www.pacificorp.com/es/dsm.html.
(2)(a)	Plan addresses supply in terms of current and future needs.	The 2011 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the Company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Chapter 5. For example, see Table 5.11 for PacifiCorp's capacity load and resource balance.
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Chapter 7.
(2)(b)	LRC analysis considers resource costs.	Chapter 6, Resource Options, provides detailed information on costs and other attributes for all resources analyzed for the IRP. For example, see Tables 6.1 through 6.8, 6.10, and 6.12.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. See the section entitled, "Monte Carlo Production Cost Simulation" in Chapter 7 for a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
		commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints,
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory costs, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Chapter 9 covers the following topics: (1) managing carbon risk for existing plants, (2) managing gas supply risk, and (3) procurement delays. Chapter 4 covers similar risks associated with transmission system expansion.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	The IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington, Oregon, California, and Utah. (See Chapter 7, "Representation and Modeling of Renewable Portfolio Standards", as well as Appendix A for RPS compliance reports developed for each resource portfolio assessed for the IRP). PacifiCorp also evaluated various CO_2 regulatory schemes, including a CO_2 tax, hard cap, and cap-and-trade. Future modeling enhancements are planned for improved representation of state-level resource regulations.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	Criteria pollutant and CO_2 emissions under the Clean Air Act are discussed in Chapter 3. A description of PacifiCorp's modeling of CO_2 cost risk is provided in Chapter 7. Chapter 9 discusses the implications of CO_2 cost uncertainty on resource acquisition plans.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Chapter 6, "Demand-side Resources".
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic short-term and long-term variability. Details concerning the load forecasts used in the 2011 IRP are provided in Chapters 5 and 8, and Appendix A. Figures 7.4 in Chapter 7 show the range of forecasts used for capacity expansion modeling. Figures 7.18 through 7.24 show the range of stochastic loads modeled for each load area by the Monte Carlo production cost simulations.
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Chapter 5, "Load Forecast", for a description of the load forecasting methodology.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Appendix A, Load Forecast Details, for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp updated the system-wide demand-side management potential study in 2010, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. As noted above, the 2010 DSM potentials study is available on PacifiCorp's DSM Web site.
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Chapter 5, Resource Needs Assessment ("Existing Resources").
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Chapters 6 and 7 document how PacifiCorp developed and assessed these technologies.
(3)(d)	Plan includes an assessment of transmission system capability and reliability (as allowed by current law).	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans (See Chapters 4 and 7). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. The DSM potentials study considered improvements in conservation Distribution considered alternative transmission expansion options.
(3)(f)	Demand forecasts and resource evaluations are integrated into the long range plan for resource acquisition.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Chapter 7. Portfolio evaluation covers a 20-year period (2011-2030). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.1, Chapter 9, for PacifiCorp's 2011 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	A status report on action plan implementation is provided in the "Progress on Previous Action Plan Items" section of Chapter 9.
(5)	Plan includes description of consultation with commission staff. (Description not required)	Chapter 2 includes a summary of the 2011 IRP public process, while Appendix F provides details on specific meetings held.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2011 IRP
(5)	Plan includes description of completion of work plan. (Description not required)	Not applicable; the IRP schedule was modified to accommodate planning events. See the response to WAC 480-100-238(4).

Table B.6 – Wyoming Public Service Commission IRP Standard and Guidelines (Docket 90000-107-XO-09)

No.	Requirement	How the Guideline is Addressed in the 2011 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 Chapter 2. A record of public meetings is provided as Appendix F.
B	The utility's strategic goals and resource planning goals and preferred resource portfolio	Chapters 9 and 10 presents the 2011 IRP and transmission expansion action plans, respectively. Chapter 8 presents the preferred portfolio. Additionally, the acquisition path analysis (Table 9.2) describes alternative resource strategies based on trigger events and trends.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Chapter 5, Resource Needs Assessment.
D	A study detailing the types of resources considered;	Chapter 6, Resource Options, presents the resource options used for resource portfolio modeling for this IRP.
F	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 2008 IRP Update is presented as Table 9.3 in Chapter 9. A chart comparing the peak load forecasts for the 2008 IRP, 2008 IRP Update, and 2011 IRP is included in Appendix A.
G	The environmental impacts considered;	Tables and graphs showing CO_2 and EPA criteria pollutant emissions are presented in Chapter 8 and Appendix E.
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in this IRP.
H	Reserve Margin analysis; and	PacifiCorp's stochastic loss of load study and selection of a capacity planning reserve margin is included as Appendix J.
I	Demand-side management and conservation options;	See Chapter 6 for a detailed discussion on DSM and conservation resource options.

APPENDIX C – ENERGY GATEWAY SCENARIO PORTFOLIOS

This appendix provides additional modeling inputs and results for the Energy Gateway transmission scenarios documented in Chapter 4 of Volume 1. The appendix consists of detailed transmission cost information incorporated into System Optimizer and portfolio Present Value Revenue Requirements (PVRR) reporting, as well as resource tables indicating resource differences between the base Energy Gateway portfolio (developed assuming only the Energy Gateway Central segments are built) and portfolios developed with incremental Energy Gateway segments.

Transmission Scenario Analysis and Cost Details

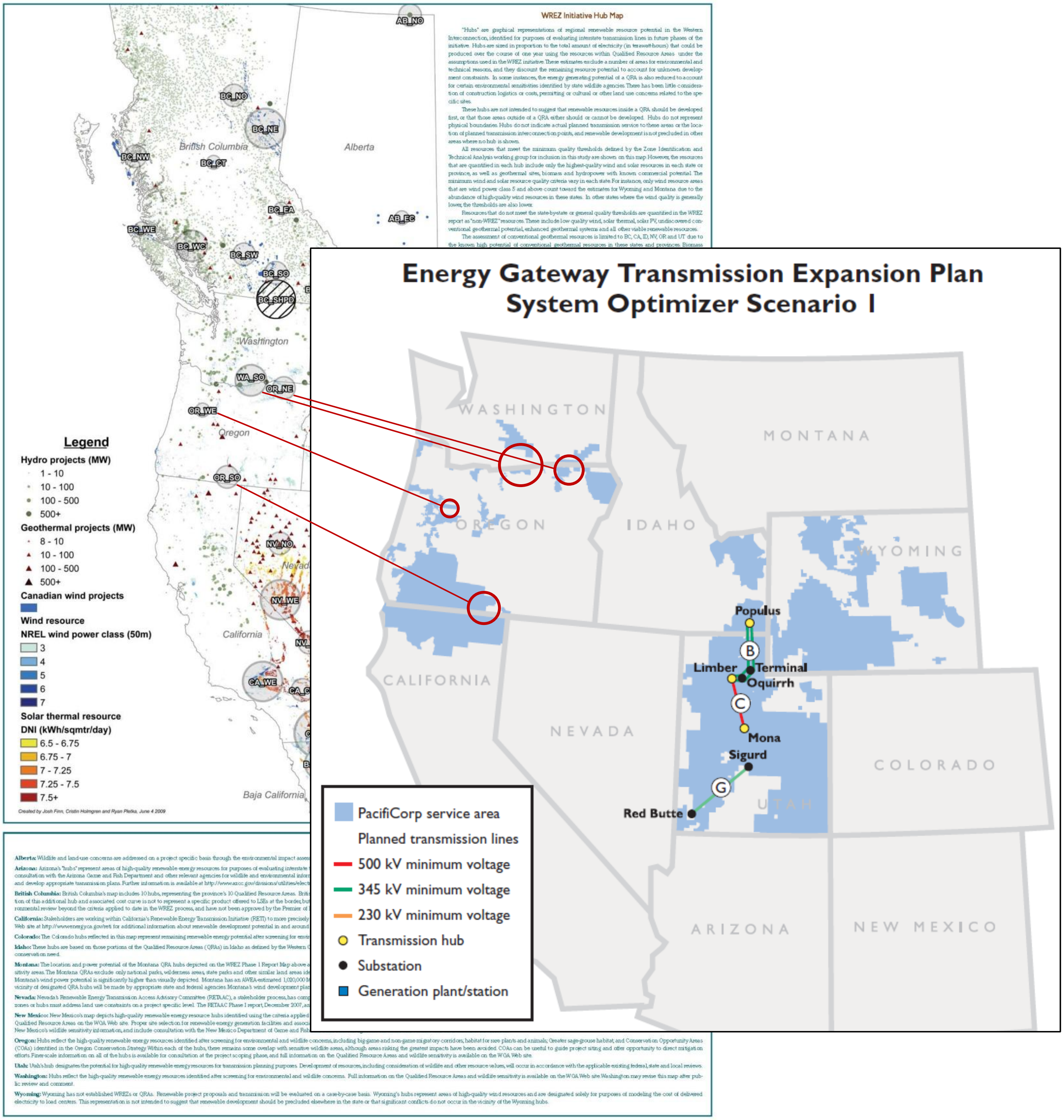
The *Transmission Scenario Analysis* section of Chapter 4, Transmission Planning, assesses resource additions and 20-year present value revenue requirement (PVRR) for various Energy Gateway scenarios. These scenarios range from a "base case" strategy with the minimal planned transmission (Scenario 1 – including the Populus to Terminal, Mona to Oquirrh, and Sigurd to Red Butte projects) to the full "incremental" Energy Gateway strategy (Scenario 7 – including Gateway Central, Gateway West, Gateway South and west-side projects). The PVRR calculations are for 20-years discounted back to 2011 dollars assuming a 7.17 percent discount rate in order to be consistent with other IRP analyses. However, a full financial analysis would assume a 58-year lifecycle and include stochastic analysis through the Planning and Risk (PaR) model as described in Chapter 7.

The System Optimizer's selection of wind resources for the "Green Resource Future" used various Energy Gateway scenarios as input assumptions and then determined general placement of additional wind resources. Wind resource requirements were assumed at the Waxman-Markey level (20 percent by 2020). The System Optimizer acts as a screening tool for resource selection but has limited ability to take into account transmission constraints and/or operational requirements. This limitation requires Transmission Planning, in some cases, to choose between planning adequate transmission facilities appropriate for the resource location, moving wind resources to alternative renewable energy zones, or both.

PacifiCorp's Transmission Planning Department did not pre-determine the entire transmission infrastructure/cost for each scenario, other than providing the Energy Gateway scenarios as tested using System Optimizer. However, The Transmission Planning Department determined whether the wind resources selected by the System Optimizer had adequate location-based transmission facilities and, in one scenario, relocated wind resources in consideration of transmission constraints and operational considerations. Placement and megawatt capacity of wind resources in scenarios 1, 3 and 7 selected by the System Optimizer were left as is; however, resource-location-dependent transmission was added to accommodate the incremental resources. In scenario 2, The Transmission Planning Department determined that some of the resources selected for Wyoming had to be relocated to Utah due to transmission constraints and operational limits.

West-side wind resource additions under the "Green Resource Future" (see Table 4.1) for Scenario 1 range between 871 MW and 1,021 MW of new wind generation primarily in Washington. Figure C.1, the Western Renewable Energy Zones map, shows "bubbles" in Washington and Oregon where wind resources are strongest, plus the Energy Gateway Scenario 1 map which shows PacifiCorp's service area in blue.

Figure C.1 – Western Renewable Energy Zones plus Energy Gateway Scenario 1



Source: Western Renewable Energy Zones – Phase 1 Report (http://www.westgov.org/rtep/219)

Tables C.1 and C.2 outline the line item details for the transmission costs presented in Tables 4.2 and 4.4 of Chapter 4. Given that Scenario 1 includes no incremental transmission capacity on the west side and lacked available capacity in this region, new transmission additions would be required to bring up to 1,021 MW of west-side wind generation to customer load centers in Oregon, Washington and California. PacifiCorp estimated that $1.5 billion (20-Year PVRR) in new west-side transmission investment would be required to deliver this energy to customers under the Green Resource Scenario. [2]

[2] See the west side line items in Table C.1.

Table C.1 – Transmission Cost Details, Green Resource Future

Transmission Cost, Present Value of Revenue Requirement ($ millions)

Transmission Cost Detail Table 4.2	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 7**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 7**
CO_2 Tax	**Medium**	**Medium**	**Medium**	**Medium**	**Medium**	**Medium**	**Medium**	**Medium**
Natural Gas Costs	**Medium**	**Medium**	**Medium**	**Medium**	**High**	**High**	**High**	**High**
Capital Recovery (Energy Gateway)								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	142	107	105	45	142	107	105	45
Utah	0	475	0	0	0	475	0	0
West side [1/]	1,503	0	0	0	1,503	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	36	35	35	35	35
Total (20-year PVRR) [2/]	**$3,103**	**$2,499**	**$2,524**	**$2,564**	**$3,103**	**$2,499**	**$2,524**	**$2,563**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	337	253	248	107	337	253	248	107
Utah	0	1,124	0	0	0	1,124	0	0
West side [1/]	2,802	0	0	0	2,802	0	0	0
Total Gross Capital [3/]	**$4,915**	**$4,706**	**$4,857**	**$5,995**	**$4,915**	**$4,706**	**$4,857**	**$5,995**

Transmission Cost Detail Table 4.2	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 7**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 7**
CO_2 Tax	**High**	**High**	**High**	**High**	**High**	**High**	**High**	**High**
Natural Gas Costs	**Medium**	**Medium**	**Medium**	**Medium**	**High**	**High**	**High**	**High**
Capital Recovery								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	142	107	105	45	142	107	105	45
Utah	0	475	0	0	0	475	0	0
West side [1/]	1,503	0	0	0	1,503	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	35	36	36	36	36
Total (20-year PVRR) [2/]	**$3,103**	**$2,499**	**$2,524**	**$2,563**	**$3,104**	**$2,500**	**$2,525**	**$2,564**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	337	253	248	107	337	253	248	107
Utah	0	1,124	0	0	0	1,124	0	0
West side [1/]	2,802	0	0	0	2,802	0	0	0
Total Gross Capital [3/]	**$4,915**	**$4,706**	**$4,857**	**$5,995**	**$4,915**	**$4,706**	**$4,857**	**$5,995**

[1/] Westside Resource Location Dependent Transmission assumed to be in-service the beginning of year 2016.

[2/] Transmission depreciable assets have a 58-year book life, however the present value revenue requirements were based on 20-years of future transmission costs using a 7.17% discount rate in order to be consistent with IRP date parameters.

[3/] Gross capital estimates came from standard transmission base assemblies priced in 2009 except for the Populus - Terminal segment where 2010 forecasted completion costs were used.

Table C.2 – Transmission Cost Details, Incumbent Resource Future

Transmission Cost, Present Value of Revenue Requirement ($ millions)

Transmission Cost Detail Table 4.4	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Capital Recovery (Energy Gateway)								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	0	0	0	0	0	0	0	0
Utah	0	0	0	0	0	0	0	0
West side	0	0	0	0	0	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	35	35	35	35	35
Total (20-year PVRR) [1/]	**$1,458**	**$1,916**	**$2,419**	**$2,518**	**$1,457**	**$1,916**	**$2,419**	**$2,518**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	0	0	0	0	0	0	0	0
Utah	0	0	0	0	0	0	0	0
West side	0	0	0	0	0	0	0	0
Total Gross Capital [2/]	**$1,776**	**$3,329**	**$4,609**	**$5,888**	**$1,776**	**$3,329**	**$4,609**	**$5,888**

Transmission Cost Detail Table 4.4	Scenario 1	Scenario 2	Scenario 3	Scenario 7	Scenario 1	Scenario 2	Scenario 3	Scenario 7
CO_2 Tax	High	High	High	High	High	High	High	High
Natural Gas Costs	Medium	Medium	Medium	Medium	High	High	High	High
Capital Recovery								
Gateway Central (Populus - Terminal and Mona-Oquirrh)	$1,118	$920	$945	$738	$1,118	$920	$945	$738
Sigurd - Red Butte	295	295	295	295	295	295	295	295
Harry Allen Upgrade	9	9	9	9	9	9	9	9
Windstar to Populus	0	657	657	657	0	657	657	657
Aeolus - Mona	0	0	477	307	0	0	477	307
Populus - Hemingway	0	0	0	270	0	0	0	270
Hemingway - Boardman - Cascade Crossing	0	0	0	207	0	0	0	207
Resource Location Dependent Transmission								
Wyoming/Idaho	0	0	0	0	142	107	105	45
Utah	0	0	0	0	0	475	0	0
West side	0	0	0	0	0	0	0	0
Wheeling Charge (Southwest, UT - Mead, NV)	35	35	35	35	36	36	36	36
Total (20-year PVRR) [1/]	**$1,458**	**$1,916**	**$2,419**	**$2,518**	**$1,600**	**$2,499**	**$2,525**	**$2,564**
Gross Capital								
Energy Gateway Capital	$1,776	$3,329	$4,609	$5,888	$1,776	$3,329	$4,609	$5,888
Resource Location Dependent Transmission:								
Wyoming/Idaho	0	0	0	0	337	254	248	107
Utah	0	0	0	0	0	1,123	0	0
West side	0	0	0	0	0	0	0	0
Total Gross Capital [2/]	**$1,776**	**$3,329**	**$4,609**	**$5,888**	**$2,113**	**$4,706**	**$4,857**	**$5,995**

[1/] Transmission depreciable assets have a 58-year book life, however the present value revenue requirements were based on 20-years of future transmission costs using a 7.17% discount rate in order to be consistent with IRP date parameters.

[2/] Gross capital estimates came from standard transmission base assemblies priced in 2009 except for the Populus - Terminal segment where 2010 forecasted completion costs were used.

System Optimizer Portfolio Tables

This section presents System Optimizer portfolio output tables for the Energy Gateway transmission scenarios discussed in Chapter 4, Transmission Planning. Table C.3 summarizes the input assumptions used for developing each Energy Gateway portfolio. Table C.4 reports the portfolio PVRRs, indicating post-model-run adjustments for transmission costs and reversal of the stochastic value adjustment applied to CCCT resources. (See Chapter 7 for a discussion of this adjustment). Table C.5 consists of the resource capacity difference tables. The base Energy Gateway scenario is shown first, followed by the resource difference tables for scenarios with the matching input assumptions. For example, resource differences for scenarios EG2, EG3, and EG4 are shown with respect to EG1. Portfolios designated with the “WM” suffix correspond to the Green Resource Future strategy outlined in Chapter 4.

Table C.3 – Energy Gateway Scenario Development Table

Case #	Assumption Alternatives									
	Carbon Policy		Gas Price 2/	Load Growth 3/	Renewable PTC and Wind Integration Cost 4/	Renewable Portfolio Standards 5/	Demand-Side Management	Distributed Solar 10/	Coal Plant Utilization	Energy Gateway Trans 12/
	Type 1/ CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable 6/ Class 3 Included 7/ Technical Potential 8/ Distribution Efficiency 9/	Current Incentives UT Buydown Levels	No shutdowns Optimized 11/	Base Scenario 1 Scenario 2 Scenario 3
Energy Gateway Scenario Evaluation Cases										
EG1	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG2	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG3	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG4	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG5	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG6	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG7	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG8	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG9	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG10	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG11	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG12	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG13	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base
EG14	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 1
EG15	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 2
EG16	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Scenario 3
EG1-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG2-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG3-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG4-WM	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG5-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG6-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG7-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG8-WM	CO2 Tax	Medium	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG9-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG10-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG11-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG12-WM	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3
EG13-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Base
EG14-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 1
EG15-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 2
EG16-WM	CO2 Tax	High	High	Med. Econ. Growth	Extension to 2015	Federal RPS	High Achievable	Current Incentives	None	Scenario 3

Table C.4 – Energy Gateway Scenario PVRR Results

Case	System Optimizer Output PVRR ($ millions)	Post-run transmission adjustment ($ millions)	Apply CCCT option value adjustment ($ millions)	Adjusted PVRR ($ millions)	Scenario	PVRR Difference from Base ($ millions)
EG 1	40,789	142	193	41,124	Base	41,124
EG 2	41,232	583	193	42,007	1	883
EG 3	41,734	105	193	42,032	2	908
EG 4	40,501	45	204	40,750	3	(374)
EG 5	41,890	142	132	42,165	Base	42,165
EG 6	42,278	583	132	42,994	1	829
EG 7	42,781	105	132	43,019	2	854
EG 8	41,656	45	157	41,858	3	(307)
EG 9	45,820	142	193	46,155	Base	46,155
EG 10	46,261	583	193	47,036	1	881
EG 11	46,763	105	193	47,061	2	906
EG 12	45,558	45	204	45,807	3	(348)
EG 13	46,941	0	132	47,074	Base	47,074
EG 14	47,737	0	132	47,869	1	795
EG 15	47,174	0	132	47,306	2	233
EG 16	46,581	0	157	46,737	3	(336)

Case	System Optimizer Output PVRR ($ millions)	Post-run transmission adjustment ($ millions)	Apply CCCT option value adjustment ($ millions)	Adjusted PVRR ($ millions)	Scenario	PVRR Difference from Base ($ millions)
EG 1_WM	41,739	-1,503	204	40,439	Base	40,439
EG 2_WM	40,847	0	204	41,050	1	611
EG 3_WM	40,870	0	204	41,074	2	635
EG 4_WM	40,909	0	204	41,113	3	674
EG 5_WM	42,693	-1,503	204	41,394	Base	41,394
EG 6_WM	41,797	0	204	42,001	1	607

Case	**System Optimizer Output PVRR** ($ millions)	**Post-run transmission adjustment** ($ millions)	**Apply CCCT option value adjustment** ($ millions)	**Adjusted PVRR** ($ millions)	**Scenario**	**PVRR Difference from Base** ($ millions)
EG 7_WM	41,821	0	204	42,024	2	630
EG 8_WM	41,859	0	204	42,062	3	668
EG 9_WM	46,706	-1,503	204	45,406	Base	45,406
EG 10_WM	45,793	0	204	45,997	1	591
EG 11_WM	45,815	0	204	46,019	2	612
EG 12_WM	45,854	0	204	46,057	3	651
EG 13_WM	47,691	-1,503	204	46,392	Base	46,392
EG 14_WM	46,775	0	204	46,979	1	587
EG 15_WM	46,752	0	204	46,956	2	564
EG 16_WM	46,784	0	204	46,988	3	596

Table C.5 – Energy Gateway Scenario Portfolio Results

Energy Gateway Case 1

PVRR $41,124 million

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	Resource Sum, FOT Average 20 Year *
	Capacity (MW)																					
East																						
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	-	-	2
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	-	-	2
CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	-	0.9	4.0	-	20	25
DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
DSM, Class 1, Utah-DLC-Residential	21.0	10.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1 Total	26.5	40.6	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	-	0.9	4.0	-	87	92
DSM, Class 2, Idaho	2.0	2.5	2.2	2.8	3.4	3.9	4.2	4.4	4.3	4.6	4.7	4.8	5.7	6.1	6.5	6.1	6.5	6.1	6.1	5.6	34	92
DSM, Class 2, Utah	83.9	92.1	93.9	40.1	41.4	43.9	45.1	46.1	47.8	50.1	51.4	54.9	51.3	53.1	53.0	57.4	52.0	54.6	53.8	56.2	584	1,122
DSM, Class 2, Wyoming	3.6	4.6	4.8	5.5	5.6	6.3	6.9	8.7	8.7	9.3	10.9	11.5	13.3	16.3	17.4	22.5	23.9	28.1	35.0	37.2	64	280
DSM, Class 2 Total	89.6	99.2	100.9	48.4	50.3	54.1	56.2	59.1	60.8	64.0	66.9	71.1	70.3	75.6	76.8	86.0	82.4	88.8	94.9	99.1	683	1,494
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	2	-	-	-	-	-	2	-	-	-	24	28
Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
FOT Mead 3rd Qtr HLH	-	168	264	254	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	785	785
FOT Utah 3rd Qtr HLH	154	200	200	-	200	-	-	78	174	87	-	-	-	-	-	-	-	-	-	-	1,092	1,092
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	25	134	238	290	300	300	300	300	300	300	225	237
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	2	37	65	69	105	173	83	172	143	151	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	27	282	343	328	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	5	17	59	100	36	259	273	252	N/A	100
West																						
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	4	41	-	56
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	4	41	-	56
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	-	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	0.5	-	-	12.7	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	3.6	6.5	-	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	3.8	-	-	4.7	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	-	-	4.3	-	-	48.4	6.5	-	-	-	-	-	-	-	-	-	-	-	59	59
DSM, Class 2, California	0.6	0.8	0.8	1.1	1.3	1.4	1.5	1.5	1.4	1.6	1.6	1.6	2.0	2.1	2.2	2.0	2.0	1.9	1.9	1.9	12	31
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	10.0	12.5	8.2	8.0	8.4	8.2	8.5	8.8	9.3	9.5	10.0	10.9	10.9	11.4	11.8	9.3	8.1	8.5	8.6	8.9	91	190
DSM, Class 2 Total	63.2	66.1	65.0	69.8	71.4	70.4	70.3	62.7	63.1	63.4	63.9	64.9	65.3	65.9	66.3	63.7	54.1	46.4	46.5	46.9	665	1,249
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	1	1	1	1	-	-	1	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	393	400	400	400	400	400	400	400	400	400	400	400	400	400	400	359	380
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	193	147	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	17
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	26	50	-	36	50	50	50	-	-	-	-	-	-	-	-	-	-	26	13
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	65	205	-	-	172	N/A	44
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	125	-	-	-	N/A	12
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	77	61	26	-	169	149	175	52	177	146	N/A	103
Annual Additions, Long Term Resources	206	295	191	760	268	753	140	192	189	141	145	146	146	152	187	159	151	156	159	196		
Annual Additions, Short Term Resources	304	1,112	1,311	1,131	1,099	693	736	828	924	837	503	632	733	777	1,037	1,205	1,350	1,465	1,636	1,749		
Total Annual Additions	510	1,406	1,502	1,890	1,367	1,446	876	1,020	1,113	978	649	778	879	928	1,224	1,364	1,501	1,621	1,795	1,945		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 2 compared to Energy Gateway Case 1

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $883 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	-	-	(2)	-	-	-	-	(4)
	FOT Utah 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	1	1	6	10	-	-	-	-	-	-	-	17
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(2)	(13)	6	4	40	(27)	-	(8)	-	-	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	39	(11)	(46)	(8)	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(12)	(45)	(38)	87	13	28	(27)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(1)	-	-	-	-	(5)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	40	-	-	-	28	N/A	7
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(125)	-	-	-	N/A	(12)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	2	14	(5)	-	1	1	3	10	22	12	N/A	6
	Annual Additions, Long Term Resources	-	-	-	-	-	-	0	-	-	-	(3)	(1)	(1)	(1)	-	-	1	(2)	(1)	(7)		
	Annual Additions, Short Term Resources	-	-	-	-	-	-	(0)	(0)	(0)	(0)	1	1	2	2	2	2	3	4	4	5		
	Total Annual Additions	-	-	-	-	-	-	0	(0)	(0)	(0)	(2)	0	1	1	2	2	4	2	3	(2)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 3 compared to Energy Gateway Case 1

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $908 million

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	20 Year *
East																							
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	-	-	(2)	-	-	-	-	(4)
	FOT Utah 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	1	1	6	10	-	-	-	-	-	-	-	17
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(2)	(13)	6	4	40	(27)	-	(8)	-	-	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	39	(11)	(51)	(3)	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(12)	(45)	(38)	87	13	33	(32)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(1)	-	-	-	-	(5)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	40	-	-	-	28	N/A	7
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(125)	-	-	-	N/A	(12)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	2	14	(5)	-	1	1	3	10	22	12	N/A	6
	Annual Additions, Long Term Resources	-	-	-	-	-	-	0	-	-	-	(3)	(1)	(1)	(1)	-	-	1	(2)	(1)	(7)		
	Annual Additions, Short Term Resources	-	-	-	-	-	-	(0)	(0)	(0)	(0)	1	1	2	2	2	2	3	4	4	5		
	Total Annual Additions	-	-	-	-	-	-	0	(0)	(0)	(0)	(2)	0	1	1	2	2	4	2	3	(2)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 4 compared to Energy Gateway Case 1

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR ($374) million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	597	(597)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	(45)	45	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	6	9	4	34	-	74
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	6	9	4	34	-	74
	CHP - Reciprocating Engine	(1)	(1)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	-	-	-	-	-	-	(0.9)	0.9	-	-	(0)
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1, Utah-Curtailment	-	(19.5)	19.5	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-DLC-Residential	(21.0)	(10.7)	-	-	-	-	25.7	-	-	11.3	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	(21.0)	(28.2)	19.5	19.8	(19.8)	-	32.0	-	-	11.3	-	-	-	-	-	-	-	(0.9)	0.9	-	14	14
	DSM, Class 2, Idaho	(0.5)	(0.7)	(0.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)
	DSM, Class 2, Utah	(40.6)	(45.5)	(54.9)	-	-	-	1.9	2.0	2.1	3.4	-	-	-	-	-	-	-	-	-	-	(132)	(132)
	DSM, Class 2, Wyoming	(0.2)	(0.2)	0.3	0.6	0.7	0.8	1.0	-	-	0.2	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2 Total	(41.3)	(46.4)	(54.8)	0.6	0.7	0.8	2.9	2.0	2.1	3.6	-	-	-	-	-	-	-	-	-	-	(130)	(130)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	0	2	2	0	-	-	(2)	-	-	-	-	3
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
	FOT Mead 3rd Qtr HLH	-	-	-	10	(99)	62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	FOT Utah 3rd Qtr HLH	96	50	50	63	(200)	-	62	122	(174)	113	-	-	-	-	-	-	-	-	-	-	183	183
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	275	166	62	10	-	-	-	-	-	-	-	513
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(2)	7	56	102	(4)	(57)	0	(48)	(26)	(30)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	(27)	9	10	6	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	(5)	(2)	(51)	(6)	(36)	93	(59)	65	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	(4)	(41)	-	(56)
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(0.5)	-	-	(12.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	(3.6)	(6.5)	0.3	-	-	-	-	-	-	-	-	-	-	(6)	(6)
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	(3.8)	-	6.4	(4.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	0.7	-	-	-	4.1	(4.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	42.2	-	(4.3)	-	10.5	(48.4)	(6.5)	0.3	-	-	-	-	-	-	-	-	-	-	(6)	(6)
	DSM, Class 2, California	0.1	-	-	-	-	-	-	-	0.2	0.2	-	-	-	-	-	-	-	-	-	(0.2)	0	0
	DSM, Class 2, Washington	0.1	0.1	-	0.4	-	0.1	-	0.3	-	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.2	0.1	-	0.4	-	0.1	-	0.3	0.2	0.3	-	-	-	-	-	-	-	-	-	(0.2)	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	(1)	-	-	-	-	-
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	(59)	7	-	-	(29)	-	(84)	-	-	-	-	-	-	-	-	-	(8)	(8)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	51	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	6
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	24	(50)	50	14	-	(50)	-	-	-	-	-	-	-	-	-	-	-	9	4
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	205	113	(0)	13	195	16	N/A	54
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180	-	-	-	N/A	18
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(77)	(61)	(2)	1	(40)	59	(6)	46	(8)	57	N/A	(3)
	Annual Additions, Long Term Resources	(64)	(127)	5	21	574	(596)	45	(46)	(49)	60	0	2	2	0	1	21	3	(3)	0	(7)		
	Annual Additions, Short Term Resources	96	151	160	97	(408)	120	75	122	(253)	113	113	112	111	111	111	111	112	113	113	114		
	Total Annual Additions	32	24	165	117	165	(476)	121	76	(302)	174	113	115	114	111	112	132	115	111	113	107		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 5

PVRR $42,165 million

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource sum, FOT Average 10 Year	20 Year *
East																							
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
	CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	-	20	25
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	3.2	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	31.7	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	5.4	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	61.6	-	-	28.4	8.4	-	-	-	-	-	-	-	-	-	-	4.9	-	-	-	104	109
	DSM, Class 2, Idaho	2.0	2.5	2.5	3.0	3.7	4.4	4.7	4.9	5.0	5.4	5.2	5.6	6.7	7.3	7.6	7.2	7.7	7.6	7.6	7.1	38	108
	DSM, Class 2, Utah	83.9	92.1	101.2	44.0	64.3	67.2	66.5	50.6	61.3	69.5	55.5	59.6	57.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	701	1,296
	DSM, Class 2, Wyoming	3.9	5.0	5.3	6.2	6.3	7.3	8.1	8.9	9.0	9.7	11.1	11.8	13.7	16.8	17.9	23.5	25.0	29.5	36.7	39.9	70	295
	DSM, Class 2 Total	89.8	99.6	109.0	53.2	74.3	78.9	79.3	64.5	75.2	84.6	71.8	77.0	78.2	84.2	85.7	94.1	89.9	97.2	103.6	109.1	808	1,699
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	0	-	-	-	-	24	37
	Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
	FOT Mead 3rd Qtr HLH	-	168	264	214	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	845	845
	FOT Utah 3rd Qtr HLH	175	200	200	-	63	176	200	-	-	200	-	-	-	-	-	-	-	-	-	-	1,213	1,213
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	15	6	17	28	89	107	114	140	211	274	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	109	187	205	243	256	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	1	45	52	36	92	207	-	204	174	188	N/A	100
West																							
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	35	70	-	70	70	-	-	-	-	-	-	-	-	-	70	315	385
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	3.6	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	-	-	52.8	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, California	0.7	0.8	0.9	1.2	1.5	1.6	1.7	1.7	1.7	1.8	1.8	1.9	2.2	2.4	2.6	2.3	2.4	2.2	2.2	2.3	14	36
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	12.0	12.6	9.0	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.1	12.4	9.6	8.3	8.7	8.6	9.2	97	200
	DSM, Class 2 Total	65.3	66.2	65.9	70.8	72.1	71.2	70.9	63.3	63.4	63.8	65.0	66.1	66.1	66.8	67.3	64.3	54.7	46.9	46.9	47.5	673	1,264
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	1	1	1	-	-	-	-	-	16	23
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	365	395	400	71	385	400	400	400	400	400	400	400	400	356	361
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	143	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	12
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	196	-	43	18	N/A	28
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	N/A	7
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	225	-	61	102	268	162	183	308	356	336	N/A	200
	Annual Additions, Long Term Resources	188	416	200	766	399	225	276	150	267	232	153	157	157	164	166	168	159	153	160	236		
	Annual Additions, Short Term Resources	325	1,111	1,304	1,114	962	1,025	950	665	695	950	612	736	830	866	1,149	1,312	1,448	1,558	1,726	1,772		
	Total Annual Additions	513	1,527	1,505	1,880	1,361	1,250	1,226	815	962	1,182	765	892	987	1,030	1,315	1,479	1,606	1,711	1,886	2,008		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 6 compared to Energy Gateway Case 5

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $829 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Idaho	-	-	-	-	-	(0.1)	-	-	-	-	-	(0.2)	-	-	-	-	(0.2)	-	-	-	(0)	(1)
	DSM, Class 2, Utah	-	-	-	-	(18.9)	(19.0)	-	-	(0.5)	-	-	-	(2.0)	-	-	-	-	-	-	-	(38)	(40)
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.1	0.1	0.1	0.1	-	-	(0.1)	0.3	0.3	-	-	(0.1)	0.8	-	0	2
	DSM, Class 2 Total	-	-	-	-	(18.9)	(19.1)	0.1	0.1	(0.4)	0.1	-	(0.2)	(2.1)	0.3	0.3	-	(0.2)	(0.1)	0.8	-	(38)	(39)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	-	-	-	-	-	(0)
	Micro Solar - Photovoltaic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	15	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(8)	23	31	39	119	(7)	(34)	(2)	(69)	(91)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	(187)	55	37	61	N/A	-
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	3	(6)	(14)	(6)	(92)	98	-	(44)	14	48	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	70	-	(70)	35	35
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	DSM, Class 2 Total	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	0	-	(71)	(103)	-	-	-	-	-	-	-	(58)	0	(12)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(6)	-	(43)	(18)	N/A	(9)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222	-	-	-	N/A	22
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	76	86	(15)	(31)	(25)	(97)	6	(70)	-	58	N/A	(1)
	Annual Additions, Long Term Resources	-	0	-	-	(19)	16	0	0	(0)	0	-	(0)	(1)	0	0	(0)	(0)	70	1	(70)		
	Annual Additions, Short Term Resources	-	(0)	(0)	(0)	15	0	-	(0)	0	-	-	0	2	1	1	1	1	(61)	(61)	1		
	Total Annual Additions	-	0	(0)	(0)	(3)	16	0	0	(0)	0	-	(0)	0	2	1	1	1	9	(60)	(69)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 7 compared to Energy Gateway Case 5

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $854 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Idaho	-	-	-	-	-	(0.1)	-	-	-	-	-	(0.2)	-	-	-	-	(0.2)	-	-	-	(0)	(1)
	DSM, Class 2, Utah	-	-	-	-	(18.9)	(19.0)	-	-	(0.5)	-	-	-	(2.0)	-	-	-	-	-	-	-	(38)	(40)
	DSM, Class 2, Wyoming	-	-	-	-	-	-	0.1	0.1	0.1	0.1	-	-	(0.1)	0.3	0.3	-	-	(0.1)	0.8	-	0	2
	DSM, Class 2 Total	-	-	-	-	(18.9)	(19.1)	0.1	0.1	(0.4)	0.1	-	(0.2)	(2.1)	0.3	0.3	-	(0.2)	(0.1)	0.8	-	(38)	(39)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	-	-	-	-	-	(0)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	15	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(4)	23	31	39	119	(12)	(34)	(2)	(69)	(91)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	(187)	37	24	92	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(1)	(6)	(14)	(6)	(92)	102	-	(26)	26	17	N/A	(0)
West																							
	Geothermal, Greenfield	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	70	-	(70)	35	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	DSM, Class 2 Total	-	0.1	-	-	0.0	0.0	-	0.1	-	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	0	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(0)	0	-	(71)	(103)	-	-	-	-	-	-	-	(58)	0	(12)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(6)	-	(43)	(18)	N/A	(9)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222	-	-	-	N/A	22
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	76	86	(15)	(31)	(25)	(97)	6	(70)	-	58	N/A	(1)
	Annual Additions, Long Term Resources	-	0	-	-	(19)	16	0	0	(0)	0	-	(0)	(1)	0	0	(0)	(0)	70	1	(70)		
	Annual Additions, Short Term Resources	-	(0)	(0)	(0)	15	0	-	(0)	0	-	(0)	0	2	1	1	1	1	(61)	(61)	1		
	Total Annual Additions	-	0	(0)	(0)	(3)	16	0	0	(0)	0	(0)	(0)	0	2	1	1	1	9	(60)	(69)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 8 compared to Energy Gateway Case 5

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR ($307) million

	Capacity (MW)																					Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	597
	Geothermal, Greenfield	-	-	-	-	-	-	(35)	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	(1.6)	-	-	-	1.6	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	6.6	(6.6)	-	-	-	(5.4)	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	(5.4)	(1.4)	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	6.6	(4.7)	-	19.8	(25.2)	(8.4)	-	-	-	11.9	-	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 2, Idaho	(0.5)	(0.6)	(0.4)	-	-	(0.1)	(0.1)	0.1	-	-	-	(0.2)	-	-	-	-	(0.2)	-	-	-	(1)	(2)
	DSM, Class 2, Utah	(38.1)	(42.7)	(57.5)	-	(17.7)	(19.0)	(3.4)	15.5	5.7	-	-	-	(2.0)	-	-	-	-	-	-	-	(157)	(159)
	DSM, Class 2, Wyoming	(0.1)	(0.2)	(0.1)	-	-	(0.0)	0.1	0.3	0.2	0.1	-	-	(0.1)	0.3	0.3	-	-	(0.1)	(0.2)	-	0	1
	DSM, Class 2 Total	(38.6)	(43.5)	(58.0)	-	(17.7)	(19.1)	(3.4)	15.9	6.0	0.1	-	(0.2)	(2.1)	0.3	0.3	-	(0.2)	(0.1)	(0.2)	-	(158)	(161)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	-	-	-	-	-	(0)
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
	FOT Mead 3rd Qtr HLH	-	-	-	50	-	(99)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(49)	(49)
	FOT Utah 3rd Qtr HLH	25	(7)	-	-	137	(176)	(200)	-	-	-	-	-	-	-	-	-	-	-	-	-	(221)	(221)
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	34	44	58	65	47	53	(34)	(7)	(105)	(155)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	(187)	15	61	76	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(1)	(45)	(50)	(36)	13	16	3	(26)	27	99	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	(35)	-	70	-	-	-	-	-	-	-	-	-	70	-	(70)	35	35
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	0	0	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(13.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	10.3	-	(3.6)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	4.8	(6.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	(1.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	49.5	4.8	(47.6)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, California	0.1	0.1	-	-	0.0	0.0	-	0.2	0.2	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	1	1
	DSM, Class 2, Washington	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	0.1	0.2	-	-	0.0	0.0	-	0.2	0.2	0.2	-	0.1	0.1	0.1	-	-	-	-	0.3	-	1	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(62)	(46)	35	5	-	(71)	(106)	-	-	-	-	-	-	-	(43)	(7)	(14)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	102	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	11
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(50)	15	39	-	-	-	-	-	-	-	-	-	-	-	0	0
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(24)	-	(43)	(18)	N/A	(11)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	219	-	-	-	N/A	22
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	39	107	(6)	(28)	(59)	(77)	24	(43)	-	43	N/A	(0)
	Annual Additions, Long Term Resources	(33)	(99)	(9)	25	(90)	535	(45)	86	7	48	0	(0)	(1)	0	0	(0)	(0)	70	0	(70)		
	Annual Additions, Short Term Resources	25	94	111	50	137	(336)	(296)	50	44	-	0	0	2	1	1	1	1	(61)	(61)	1		
	Total Annual Additions	(8)	(5)	102	74	47	198	(341)	136	51	48	0	(0)	0	2	1	1	1	9	(60)	(69)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 9

PVRR $46,155 million

	Capacity (MW)																					Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	4
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	-	2
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	4	-	-	6
	CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
	CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	-	-	0.9	1.3	2.7	-	-	-	-	20	25
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	31.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	-	-	6.7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	61.6	-	-	19.8	-	-	11.6	-	-	-	-	-	0.9	1.3	2.7	-	-	-	-	99	103
	DSM, Class 2, Idaho	2.0	2.5	2.2	2.8	3.4	3.9	4.2	4.5	4.7	5.1	5.2	5.4	6.5	7.0	7.3	6.8	7.2	6.8	7.1	6.5	35	101
	DSM, Class 2, Utah	83.9	92.1	93.9	40.1	41.4	43.9	45.1	48.1	49.9	52.3	54.2	58.1	54.4	56.4	57.9	61.3	55.4	58.2	57.3	59.9	591	1,164
	DSM, Class 2, Wyoming	3.6	4.6	4.8	6.1	6.2	7.1	7.9	8.7	8.7	9.3	10.9	11.8	13.6	16.7	17.8	23.0	24.5	28.8	35.9	38.9	67	289
	DSM, Class 2 Total	89.6	99.3	100.9	49.0	51.0	54.9	57.2	61.3	63.3	66.6	70.3	75.3	74.5	80.1	83.0	91.2	87.1	93.8	100.3	105.3	693	1,554
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	-	-	24	44
	Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
	FOT Mead 3rd Qtr HLH	-	168	264	230	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	761	761
	FOT Utah 3rd Qtr HLH	175	200	200	-	194	-	-	56	157	69	-	-	-	-	-	-	-	-	-	-	1,051	1,051
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	5	111	216	270	300	300	300	300	300	300	225	233
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	6	73	112	117	159	124	148	141	120	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	123	294	552	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	199	23	325	303	150	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	70	105
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	2
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	2
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	-	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	-	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	0.5	-	-	12.7	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	3.3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	-	-	-	-	9.0	-	-	48.7	-	-	-	-	-	-	-	-	-	-	-	-	58	58
	DSM, Class 2, California	0.7	0.8	0.8	1.1	1.3	1.4	1.7	1.7	1.6	1.7	1.8	1.9	2.2	2.4	2.5	2.2	2.3	2.2	2.2	2.0	13	34
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	10.1	12.5	8.5	8.5	8.6	8.4	8.8	9.1	9.4	9.6	10.7	11.7	11.4	12.1	12.4	9.6	8.3	8.7	8.6	9.0	93	196
	DSM, Class 2 Total	63.3	66.2	65.3	70.3	71.5	70.6	70.7	63.2	63.3	63.7	64.8	65.9	66.0	66.8	67.2	64.2	54.6	46.9	46.9	47.0	668	1,259
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	1	1	1	1	1	-	-	-	-	-	16	21
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	386	400	400	400	400	-	26	391	308	400	400	146	-	-	-	359	263
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	143	96	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	12
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	-	29	50	50	50	-	-	-	-	-	-	-	-	-	-	38	19
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	25	53	173	49	204	96	202	199	N/A	100
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	366	-	38	596	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	478	464	-	-	8	51	106	420	306	168	N/A	200
	Annual Additions, Long Term Resources	186	316	192	761	273	754	142	207	185	144	151	154	153	160	199	170	153	156	161	919		
	Annual Additions, Short Term Resources	325	1,111	1,310	1,130	1,093	686	729	806	907	819	482	608	705	744	997	1,158	1,300	1,412	1,583	2,085		
	Total Annual Additions	510	1,427	1,502	1,891	1,366	1,440	870	1,013	1,093	963	633	762	858	904	1,196	1,328	1,454	1,568	1,744	3,004		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 10 compared to Energy Gateway Case 9

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $881 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Average 10 Year	Resource Sum, FOT Average 20 Year *
		Capacity (MW)																					
East																							
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	4	34	-	45
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	(1)	34	-	41
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	-	2
	DSM, Class 2, Wyoming	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	0	3
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(2)	(2)	(2)	(2)	(2)	-	-	-	(12)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	(0)	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(1)	(1)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	(0)	(0)	(0)	19	-	-	-	-	-	-	-	18
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	(55)	(58)	15	116	(44)	57	(31)	0	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	116	(111)	(18)	13	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(14)	(10)	152	22	(150)	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	(35)
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 1 Total	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2, California	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	(1)	-	-	-	-	-	-	(1)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(0)	-	-	-	-	-	(26)	(37)	(49)	-	-	146	-	-	-	(0)	2
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	69	88	(13)	(48)	0	(96)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(132)	-	(38)	169	N/A	(0)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	0	27	24	-	0	(51)	(73)	3	70	1	N/A	0
	Annual Additions, Long Term Resources	-	-	0	-	-	0	-	(0)	-	-	(0)	-	(0)	(2)	(3)	(2)	(2)	3	(1)	1		
	Annual Additions, Short Term Resources	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	1	2	3	4	5	5	34		
	Total Annual Additions	-	-	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(2)	(1)	0	2	7	4	35		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 11 compared to Energy Gateway Case 9

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $906 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	4	34	-	45
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	7	(1)	34	-	41
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	-	2
	DSM, Class 2, Wyoming	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	0	3
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(2)	(2)	(2)	(2)	(2)	-	-	-	(12)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	(0)	-	-	(0)	(0)	(0)	-	-	-	-	-	-	-	-	-	-	(1)	(1)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	(0)	(0)	(0)	19	-	-	-	-	-	-	-	18
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	(55)	(57)	15	83	(34)	49	0	0	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	14	(3)	(11)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	97	34	(4)	(126)	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	(35)
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 1 Total	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2, California	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	(1)	-	-	-	-	-	-	(1)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(0)	-	-	-	-	-	(26)	(17)	(49)	-	-	126	-	-	-	(0)	2
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	49	88	(13)	(28)	0	(96)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(132)	-	(38)	169	N/A	(0)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	0	27	24	-	0	(51)	(53)	3	50	1	N/A	(0)
	Annual Additions, Long Term Resources	-	-	0	-	-	0	-	(0)	-	-	(0)	-	(0)	(2)	(3)	(2)	(2)	3	(1)	1		
	Annual Additions, Short Term Resources	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	1	2	3	4	5	5	34		
	Total Annual Additions	-	-	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(2)	(1)	0	2	7	4	35		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 12 compared to Energy Gateway Case 9

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR ($348) million

	Capacity (MW)																				Resource Sum, FOT Average	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																						
CCCT F 2x1	-	-	-	-	597	(597)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4)	-	-	(4)
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	8	7	4	34	-	71
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	8	7	(1)	34	-	66
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	-	-	1.3	(1.3)	-	-	-	-	-	-	0
DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
DSM, Class 1, Utah-Curtailment	-	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, Utah-DLC-Residential	6.6	(6.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	(6.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1 Total	6.6	(4.8)	-	19.8	(19.8)	-	6.3	(11.6)	-	-	-	-	-	1.3	(1.3)	-	-	-	-	-	(3)	(3)
DSM, Class 2, Idaho	(0.5)	(0.7)	(0.1)	-	-	-	-	(0.2)	(0.4)	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
DSM, Class 2, Utah	(38.1)	(42.7)	(50.4)	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	2.2	(129)	(127)
DSM, Class 2, Wyoming	0.1	0.2	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 2 Total	(38.5)	(43.2)	(50.1)	-	-	-	1.9	(0.2)	(0.4)	-	-	-	-	-	-	-	-	-	-	2.2	(131)	(128)
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)	-	-	-	(5)
Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
FOT Mead 3rd Qtr HLH	-	-	-	34	(99)	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(53)	(53)
FOT Utah 3rd Qtr HLH	25	(8)	-	13	(194)	-	41	123	(157)	123	-	-	-	-	-	-	-	-	-	-	(33)	(33)
FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	295	189	84	30	-	-	-	-	-	-	-	598
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	1	(55)	(84)	(41)	68	22	71	18	1	-	0
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	78	22	(157)	N/A	0
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	151	34	(45)	(150)	N/A	0
West																						
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	(35)
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	-	-	-	(2)
CHP - Reciprocating Engine	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(0.5)	-	-	(12.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, Oregon-DLC-Residential	-	-	10.3	-	-	-	-	(10.0)	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	(8.5)	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	-	(3.3)	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
DSM, Class 1 Total	-	-	49.5	-	(9.0)	-	6.4	(48.7)	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
DSM, Class 2, California	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 2, Washington	0.1	0.2	0.2	-	-	-	(0.3)	(0.3)	(0.1)	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
DSM, Class 2 Total	0.1	0.2	0.3	-	-	-	(0.3)	(0.3)	(0.1)	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)	(0)
FOT MidColumbia 3rd Qtr HLH	-	-	-	-	(109)	14	-	-	(90)	-	-	181	9	69	-	-	254	157	-	-	(18)	24
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	101	110	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	11
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	(50)	50	21	-	(50)	-	-	-	-	-	-	-	-	-	-	-	(3)	(1)
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(6)	106	36	(40)	(0)	(96)	(0)	(0)	N/A	(0)
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(366)	-	(38)	404	N/A	-
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(172)	(246)	92	-	129	85	7	(119)	168	57	N/A	(0)
Annual Additions, Long Term Resources	(33)	(99)	(1)	20	568	(597)	14	(61)	(1)	(0)	-	(0)	-	1	(1)	18	6	3	(1)	1		
Annual Additions, Short Term Resources	25	94	110	47	(452)	76	63	123	(297)	123	123	123	123	122	123	123	124	125	125	154		
Total Annual Additions	(7)	(5)	109	67	116	(521)	77	62	(298)	123	123	123	123	123	122	141	130	128	124	155		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 13

PVRR $47,074 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1
	CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	50	100
	CHP - Reciprocating Engine	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	19.8	-	-	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	20	25
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	3.2	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	31.7	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	5.4	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	61.6	-	-	28.4	8.4	-	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	104	109
	DSM, Class 2, Idaho	2.0	2.5	2.5	3.0	3.7	4.4	4.7	5.1	5.0	5.4	5.4	5.6	7.0	7.6	8.0	7.6	8.0	7.6	7.6	7.1	38	110
	DSM, Class 2, Utah	83.9	92.1	101.2	44.0	45.4	48.2	61.8	50.6	60.8	69.5	57.2	61.5	57.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	657	1,256
	DSM, Class 2, Wyoming	3.9	5.0	5.3	6.2	6.3	7.3	8.1	9.0	9.1	9.8	11.1	11.8	13.9	17.2	18.3	23.6	25.1	30.1	37.5	39.9	70	298
	DSM, Class 2 Total	89.8	99.6	109.0	53.2	55.5	59.9	74.6	64.6	74.8	84.7	73.8	78.9	78.7	84.9	86.5	94.7	90.3	97.8	104.4	109.1	766	1,665
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	-	-	-	24	42
	Micro Solar - Photovoltaic	1	51	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	54
	FOT Mead 3rd Qtr HLH	-	168	264	214	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	844	844
	FOT Utah 3rd Qtr HLH	175	200	200	-	74	172	200	-	-	200	-	-	-	-	-	-	-	-	-	-	1,221	1,221
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	74	225	251
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	7	32	75	76	137	184	143	123	104	117	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	165	353	458	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	138	159	111	60	139	19	20	220	135	-	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	70	70	-	70	70	-	-	-	-	-	-	35	35	-	-	350	420
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	3.6	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	-	8.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	-	-	52.8	-	6.8	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, California	0.7	0.9	0.9	1.2	1.5	1.6	1.7	1.7	1.7	2.0	1.8	1.9	2.3	2.5	2.6	2.3	2.7	2.5	2.5	2.3	14	37
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	12.0	12.7	9.0	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.5	12.8	9.9	8.5	8.9	8.9	9.3	97	202
	DSM, Class 2 Total	65.3	66.4	65.9	70.8	72.1	71.2	70.9	63.3	63.4	63.9	65.0	66.2	66.2	67.3	67.8	64.6	55.2	47.5	47.5	47.6	673	1,268
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	-	-	16	28
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	365	395	400	-	-	298	400	400	400	400	44	400	-	356	295
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	143	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	12
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	190	189	48	187	-	N/A	61
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	43	-	N/A	5
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	166	238	40	23	166	182	185	398	26	576	N/A	200
	Annual Additions, Long Term Resources	188	417	200	766	480	241	271	150	267	232	155	161	159	166	167	175	193	190	163	2,489		
	Annual Additions, Short Term Resources	325	1,111	1,304	1,114	974	1,021	950	665	695	950	611	730	824	859	1,141	1,299	1,408	1,486	1,654	767		
	Total Annual Additions	513	1,527	1,505	1,880	1,454	1,262	1,221	815	962	1,182	765	891	982	1,025	1,309	1,474	1,601	1,676	1,816	3,256		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 14 compared to Energy Gateway Case 13

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $795 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,600)	-	(1,600)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	141	200	26	29	-	996
	Total Wind	-	-	-	-	-	-	160	-	-	-	-	-	-	200	200	200	141	200	26	29	160	1,156
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	(0.3)	(0.1)	(0.2)	-	-	(0.3)	-	-	-	-	-	-	-	(1)	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	(0.3)	(1.3)	(9.7)	(14.6)	-	-	-	-	-	-	-	-	-	-	(26)	(26)
	DSM, Class 2, Wyoming	-	0.0	-	-	-	0.1	0.1	(0.0)	(0.2)	(0.2)	0.2	0.2	-	(0.1)	0.3	0.4	0.5	-	-	-	(0)	1
	DSM, Class 2 Total	-	0.0	-	-	-	0.1	(0.2)	(1.6)	(10.0)	(14.9)	0.2	0.2	(0.3)	(0.1)	0.3	0.4	0.5	-	-	-	(27)	(25)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	-	(0)
	FOT Mead 3rd Qtr HLH	-	-	-	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT Utah 3rd Qtr HLH	-	-	-	-	(0)	(0)	-	-	-	(9)	-	-	-	-	-	-	-	-	-	-	(10)	(10)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	226
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	37	5	19	3	14	(53)	(65)	7	33	0	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(24)	(165)	(67)	(179)	435	N/A	-
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(29)	(43)	26	(6)	(114)	35	(20)	(75)	17	209	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	35	-	-	-	-	-	35	-	-	(35)	(35)	-	-	35	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	0.1	-	-	-	0.0	-	-	-	-	(0.2)	0.1	-	-	0.3	0.3	0.3	-	-	-	-	(0)	1
	DSM, Class 2 Total	0.1	-	-	-	0.0	-	-	-	-	(0.2)	0.1	-	-	0.3	0.3	0.3	-	-	-	-	(0)	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(30)	(22)	-	-	51	(14)	(14)	-	-	-	356	-	-	(5)	16
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(35)	-	184	N/A	15
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	239	-	(43)	366	N/A	56
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(17)	(21)	(40)	(23)	59	-	-	(166)	192	16	N/A	0
	Annual Additions, Long Term Resources	0	0	-	-	0	0	160	33	(10)	(15)	0	(2)	2	235	201	201	106	165	26	(1,571)		
	Annual Additions, Short Term Resources	-	(0)	(0)	(0)	(0)	(0)	-	(30)	(22)	(9)	(9)	(7)	(9)	(41)	(41)	(42)	(11)	20	20	1,436		
	Total Annual Additions	0	(0)	(0)	(0)	(0)	(0)	160	4	(32)	(24)	(9)	(9)	(7)	195	160	159	95	185	46	(135)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 15 compared to Energy Gateway Case 13

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $233 million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,600)	-	(1,600)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	3	200	200	200	200	200	199	200	-	1,402
	Total Wind	-	-	-	-	-	-	160	-	-	-	-	-	3	200	200	200	200	200	199	200	160	1,562
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8.3	(8.3)	-	-	-	-	-	2.2	(2.2)	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	56.5	(56.6)	-	11.5	(9.8)	0.7	-	-	-	-	21.0	(2.2)	-	-	-	24.3	-	-	-	21.0	2	66
	DSM, Class 2, Idaho	(0.2)	0.3	0.7	0.4	0.5	0.5	0.6	1.1	0.7	0.7	0.6	0.7	0.8	0.9	0.9	1.0	(0.0)	2.1	(0.1)	1.0	5	13
	DSM, Class 2, Utah	(4.8)	(5.3)	(1.8)	1.1	8.4	8.0	3.0	12.6	2.5	(2.6)	12.4	3.0	7.0	10.5	10.2	11.2	21.0	23.5	23.0	25.3	21	168
	DSM, Class 2, Wyoming	8.4	8.9	9.6	10.1	12.1	11.7	11.0	12.2	12.8	12.9	7.7	8.4	5.5	3.7	2.3	(3.0)	(2.4)	(2.0)	(12.2)	(11.7)	110	106
	DSM, Class 2 Total	3.4	3.9	8.4	11.5	21.0	20.2	14.6	26.0	16.0	11.0	20.7	12.0	13.3	15.1	13.4	9.2	18.5	23.6	10.7	14.6	136	287
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	-	(0)
	FOT Mead 3rd Qtr HLH	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	FOT Utah 3rd Qtr HLH	(52)	-	-	-	14	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(36)	(36)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	226
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	96	66	19	(16)	(72)	(112)	23	(36)	(3)	34	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	35	-	9	(24)	(165)	(142)	(176)	462	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(109)	(32)	56	(31)	(122)	(19)	(20)	(54)	25	305	N/A	(0)
West																							
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	(35)	-	-	-	-	70	35	-	(35)	(35)	-	-	(35)	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	20.9	-	9.0	(23.5)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2, California	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.7	0.7	0.5	0.5	0.5	0.6	0.6	1.0	1.0	0.3	1.1	0.2	0.6	4	10
	DSM, Class 2 Total	(1.9)	(1.8)	(0.9)	(1.1)	(0.2)	(0.4)	1.0	1.0	0.4	0.3	1.2	(0.7)	0.0	(1.6)	(1.3)	(1.1)	(7.2)	(2.6)	(3.4)	(2.9)	(4)	(23)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	(18)	4	-	-	-	(222)	(46)	-	-	-	190	-	-	(1)	(5)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(22)	(36)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	(3)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	1	(48)	0	184	N/A	9
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	-	(43)	-	N/A	(5)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(22)	(71)	66	(23)	31	15	3	(59)	42	17	N/A	-
	Annual Additions, Long Term Resources	58	(34)	8	31	(62)	20	169	27	(19)	11	43	9	16	283	247	232	176	186	206	(1,367)		
	Annual Additions, Short Term Resources	(52)	(22)	(36)	(50)	14	1	-	(18)	4	-	(35)	(38)	(45)	(115)	(153)	(182)	(163)	(149)	(156)	1,229		
	Total Annual Additions	6	(56)	(28)	(19)	(48)	22	169	9	(14)	11	8	(29)	(29)	168	94	51	13	37	50	(138)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 16 compared to Energy Gateway Case 13

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR ($336) million

		Capacity (MW)																				Resource Sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	CCCT F 2x1	-	-	-	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	597
	Geothermal, Greenfield	-	-	-	-	-	-	(35)	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,600)	-	(1,600)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	188	200	200	200	200	200	200	199	200	-	1,786
	Total Wind	-	-	-	-	-	-	160	-	-	-	-	188	200	200	200	200	200	200	199	200	160	1,946
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	(19.8)	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah, Comm/Indus-Therm Energy Storage	-	(3.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	(1.6)	-	-	-	1.6	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	6.6	(6.6)	-	-	-	(5.4)	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	(5.4)	(1.4)	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	6.6	(4.7)	-	19.8	(25.2)	(8.4)	-	-	-	8.4	-	(2.2)	2.2	-	-	-	-	-	-	-	(3)	(3)
	DSM, Class 2, Idaho	(0.5)	(0.6)	(0.4)	-	-	(0.1)	(0.1)	-	-	-	-	-	(0.3)	-	-	-	-	-	-	-	(2)	(2)
	DSM, Class 2, Utah	(38.1)	(42.7)	(57.5)	-	-	-	(12.4)	-	0.6	-	-	-	-	-	-	-	-	-	-	-	(150)	(150)
	DSM, Class 2, Wyoming	(0.1)	(0.2)	(0.1)	-	(0.0)	(0.0)	0.1	0.1	0.1	-	0.2	0.2	-	(0.1)	0.3	0.4	0.5	-	-	-	(0)	1
	DSM, Class 2 Total	(38.6)	(43.5)	(58.0)	-	(0.0)	(0.1)	(12.5)	0.1	0.7	-	0.2	0.2	(0.3)	(0.1)	0.3	0.4	0.5	-	-	-	(152)	(151)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	-	-	(0)
	Micro Solar - Photovoltaic	(1)	(51)	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54)	(54)
	FOT Mead 3rd Qtr HLH	-	-	-	50	-	(99)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(49)	(49)
	FOT Utah 3rd Qtr HLH	25	(7)	-	-	126	(172)	(200)	-	-	-	-	-	-	-	-	-	-	-	-	-	(228)	(228)
	FOT Mona / NUB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	-	226
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	52	15	62	(49)	(36)	(53)	(64)	(0)	1	73	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	40	(165)	(164)	(186)	453	N/A	-
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	(40)	(108)	(83)	(60)	(139)	(19)	(20)	(91)	66	493	N/A	0
West																							
	Geothermal, Greenfield	-	-	-	-	-	(35)	-	70	-	-	-	-	-	35	-	-	(35)	(35)	-	-	35	-
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CHP - Reciprocating Engine	-	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	(5.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	(17.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	(13.2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon-DLC-Residential	-	-	10.3	-	(3.6)	-	(6.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	4.8	(6.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	(4.1)	-	-	-	-	2.9	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	49.5	4.8	(50.4)	-	(6.8)	-	-	2.9	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, California	0.1	-	0.0	-	0.0	-	-	-	0.2	-	0.1	-	-	-	0.3	0.3	-	-	-	-	0	1
	DSM, Class 2, Washington	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	0.1	-	0.0	-	0.0	-	-	-	0.2	-	0.1	-	-	-	0.3	0.3	-	-	-	-	0	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	(92)	(65)	35	5	-	132	333	61	-	-	-	-	356	-	-	(12)	38
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	102	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	11
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	(1)	(50)	8	6	-	-	-	-	-	-	-	-	-	-	-	(4)	(2)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(80)	(4)	(3)	(0)	184	N/A	10
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248	-	(43)	-	N/A	20
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	(144)	(238)	(40)	77	121	80	4	(68)	192	16	N/A	0
	Annual Additions, Long Term Resources	(33)	(99)	(9)	25	(76)	553	106	70	36	11	0	186	202	235	201	201	165	165	199	(1,400)		
	Annual Additions, Short Term Resources	25	94	111	50	126	(363)	(315)	43	11	-	(0)	2	(0)	(31)	(32)	(32)	(1)	30	30	1,446		
	Total Annual Additions	(8)	(5)	102	75	50	190	(210)	113	47	11	0	187	202	204	170	169	164	195	228	46		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Table C.4 – Energy Gateway Scenario Evaluation Results (WM Studies)

Energy Gateway Case 1_WM

PVRR $40,439 million

		Capacity (MW)																				Resource sum, FOT Average	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	66	98	35	-	-	-	-	-	-	-	-	-	-	-	200	200
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	18	88	43	29	-	22	-	-	-	-	300	500
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	0	0	-	-	-	-	-	-	-	-	-	-	2	2
	Total Wind	-	-	-	-	-	-	66	200	135	100	18	88	43	29	-	22	-	-	-	-	502	702
	CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	20	25
	DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	9.0	-	-	-	-	5.4	-	-	12.3	-	-	-	-	-	-	-	-	-	-	27	27
	DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1 Total	5.5	40.9	-	19.8	-	-	11.6	-	-	12.3	-	-	-	-	-	-	-	4.9	-	-	90	95
	DSM, Class 2, Idaho	1.5	1.8	2.0	2.8	3.4	3.9	4.2	4.4	4.3	4.6	4.7	4.8	5.7	6.1	6.5	6.1	6.5	6.1	6.1	5.6	33	91
	DSM, Class 2, Utah	43.3	46.6	39.0	40.1	41.4	43.9	45.1	46.1	47.8	50.1	51.4	54.9	51.3	53.1	53.0	57.4	52.0	54.6	53.8	56.2	443	981
	DSM, Class 2, Wyoming	3.5	4.3	4.5	5.5	6.2	7.1	7.9	8.7	8.7	9.3	10.9	11.5	13.3	16.3	17.4	22.5	23.9	28.1	35.0	37.2	66	282
	DSM, Class 2 Total	48.3	52.8	45.5	48.4	51.0	54.9	57.2	59.1	60.8	64.0	66.9	71.1	70.3	75.6	76.8	86.0	82.4	88.8	94.9	99.1	542	1,354
	Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	-	24	47
	FOT Mead 3rd Qtr HLH	-	168	266	266	-	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	789	789
	FOT Utah 3rd Qtr HLH	-	229	250	72	-	-	109	243	-	250	-	-	-	-	-	-	-	-	-	-	1,152	1,152
	FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	29	102	107	153	161	-	229	130	89	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	265	321	406	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	156	-	257	272	309	N/A	100
West																							
	Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	65	100	-	-	-	28	24	100	58	95	46	100	164	616
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	86	-	86
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	-	-	-	200	-	-	-	65	100	-	-	-	28	24	100	58	95	46	186	364	902
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
	DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
	DSM, Class 2, California	0.7	0.8	0.8	1.1	1.3	1.4	1.5	1.5	1.4	1.5	1.6	1.6	2.0	2.1	2.2	2.0	2.0	1.9	1.9	1.7	12	31
	DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
	DSM, Class 2, Washington	7.4	8.0	8.2	8.0	8.4	8.2	8.5	8.8	9.0	9.2	10.0	10.9	10.9	11.4	11.8	9.3	8.1	8.5	8.6	8.9	84	182
	DSM, Class 2 Total	60.7	61.6	65.0	69.8	71.4	70.4	70.3	62.7	62.8	63.1	63.9	64.9	65.3	65.9	66.3	63.7	54.1	46.4	46.5	46.7	658	1,241
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	-	16	31
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	27	400	400	400	365	400	400	400	400	400	369	400	400	400	400	400	400	400	400	400	359	378
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	-	50	50	50	15	50	-	-	-	-	-	-	-	-	-	-	36	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	29	-	-	133	116	190	186	106	104	N/A	86
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	470	-	-	62	N/A	53
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	43	102	142	251	267	194	26	310	283	N/A	162
	Annual Additions, Long Term Resources	136	188	173	776	1,017	153	225	340	333	394	161	234	188	208	177	281	205	244	196	337		
	Annual Additions, Short Term Resources	177	1,268	1,476	1,238	715	840	859	993	715	1,000	669	801	904	949	1,242	1,409	1,554	1,664	1,838	1,953		
	Total Annual Additions	312	1,456	1,649	2,013	1,732	993	1,084	1,332	1,048	1,394	830	1,034	1,092	1,157	1,419	1,690	1,759	1,908	2,033	2,290		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 2_WM compared to Energy Gateway Case 1_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $611 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(29)	-	(22)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	200	200	15	73	38	48	20	99	50	80	39	154	398	1,016
	Total Wind	-	-	-	-	-	-	94	(200)	65	100	(4)	(15)	(5)	19	20	78	50	80	39	154	58	476
	DSM, Class 1, Utah-DLC-Residential	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1 Total	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2, Wyoming	-	-	0.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	-	-	0.1	0.6	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	4	4
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	-	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT Utah 3rd Qtr HLH	-	0	-	(1)	-	-	(2)	7	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	4	53	75	(17)	(13)	-	(123)	(10)	32	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	-	(35)	(10)	(5)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	(35)	-	4	23	(9)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(164)	(616)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(86)	-	(86)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	(27)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	Total Wind	-	-	-	-	(27)	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(186)	(191)	(729)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, Washington	0.3	-	-	0.4	-	0.1	-	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	-	-	0.4	-	0.1	-	-	0.3	0.5	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(1)	(1)	-	-	(5)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	1	1
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	37	-	-	7	47	1	(38)	8	(59)	N/A	0
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	1	-	-	(15)	N/A	(1)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(41)	(53)	(75)	(6)	(47)	(0)	196	(6)	61	N/A	3
	Annual Additions, Long Term Resources	0	(0)	0	1	(27)	0	102	(200)	0	12	(4)	(15)	(5)	(9)	(5)	(23)	(13)	(19)	(10)	(32)		
	Annual Additions, Short Term Resources	(0)	(0)	(0)	(1)	0	0	(2)	7	11	-	-	-	(0)	(0)	0	1	2	4	5	5		
	Total Annual Additions	0	(0)	(0)	0	(26)	0	100	(193)	11	12	(4)	(15)	(5)	(9)	(4)	(23)	(10)	(15)	(5)	(27)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 3_WM compared to Energy Gateway Case 1_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $635 million

	Capacity (MW)																				Resource Sum, FOT Avg	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																						
Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(29)	-	(22)	-	-	-	-	(300)	(500)
Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	200	200	15	73	39	47	20	101	51	80	42	177	398	1,043
Total Wind	-	-	-	-	-	-	94	(200)	65	100	(4)	(15)	(5)	18	20	79	51	80	42	177	58	503
DSM, Class 1, Utah-DLC-Residential	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 1 Total	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 2, Wyoming	-	-	0.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 2 Total	-	-	0.1	0.6	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	4	4
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)	(3)	(2)	-	-	(10)
FOT Mead 3rd Qtr HLH	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
FOT Utah 3rd Qtr HLH	-	0	-	(1)	-	-	(2)	7	-	-	-	-	-	-	-	-	-	-	-	-	5	5
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	1	53	75	(15)	(14)	-	(123)	(10)	32	-	(0)
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	(16)	(9)	1	N/A	(0)
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	(9)	-	(14)	23	(15)	N/A	0
West																						
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(164)	(616)
Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(86)	-	(86)
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	(27)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
Total Wind	-	-	-	-	(27)	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(186)	(191)	(729)
DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 2, California	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 2, Washington	0.3	-	-	0.4	-	0.1	-	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 2 Total	0.3	-	-	0.4	-	0.1	-	-	0.3	0.5	-	-	-	-	-	-	-	-	-	-	2	2
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(2)	(1)	(1)	-	-	(6)
FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	1	1
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	39	-	-	7	48	2	(38)	7	(59)	N/A	0
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	2	-	-	(13)	N/A	(1)
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(41)	(53)	(75)	(6)	(47)	(0)	197	(6)	61	N/A	3
Annual Additions, Long Term Resources	0	(0)	0	1	(27)	0	102	(200)	0	12	(4)	(15)	(5)	(10)	(5)	(24)	(12)	(19)	(7)	(9)		
Annual Additions, Short Term Resources	(0)	(0)	(0)	(1)	0	0	(2)	7	11	-	-	0	(0)	0	1	2	3	5	6	6		
Total Annual Additions	0	(0)	(0)	0	(26)	0	100	(193)	11	12	(4)	(15)	(5)	(10)	(4)	(22)	(9)	(14)	(1)	(3)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 4_WM compared to Energy Gateway Case 1_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $674 million

	Capacity (MW)																					Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(29)	-	(22)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	200	200	15	73	39	47	20	101	51	80	43	200	398	1,067
	Total Wind	-	-	-	-	-	-	94	(200)	65	100	(4)	(15)	(5)	18	20	79	51	80	43	200	58	527
	DSM, Class 1, Utah-DLC-Residential	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 1 Total	-	(0.1)	-	-	-	-	8.6	-	-	1.9	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 2, Wyoming	-	-	0.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	-	-	0.1	0.6	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	4	4
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(3)	(3)	(2)	-	-	(10)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT Utah 3rd Qtr HLH	-	0	-	(1)	-	-	(2)	7	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	(29)	53	72	6	(15)	-	(88)	(10)	11	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	(17)	(9)	1	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	(8)	-	(63)	23	54	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(164)	(616)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(86)	-	(86)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	(27)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(27)	(27)
	Total Wind	-	-	-	-	(27)	-	-	-	(65)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(186)	(191)	(729)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2, Washington	0.3	-	-	0.4	-	0.1	-	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	-	-	0.4	-	0.1	-	-	0.3	0.5	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(2)	(1)	(1)	-	-	(6)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	1	1
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	69	-	-	7	51	2	(23)	7	(59)	N/A	5
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	2	-	-	(62)	N/A	(6)
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(41)	(53)	(72)	(6)	(51)	(0)	197	(5)	61	N/A	3
	Annual Additions, Long Term Resources	0	(0)	0	1	(27)	0	102	(200)	0	12	(4)	(15)	(5)	(10)	(5)	(24)	(12)	(19)	(6)	13		
	Annual Additions, Short Term Resources	(0)	(0)	(0)	(1)	0	0	(2)	7	11	-	-	0	(0)	0	0	2	3	5	6	6		
	Total Annual Additions	0	(0)	(0)	0	(26)	0	100	(193)	11	12	(4)	(15)	(5)	(10)	(4)	(22)	(9)	(14)	(0)	19		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 5_WM

PVRR $41,394 million

	Capacity (MW)																				Resource sum, FOT Average	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																						
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	66	77	-	-	-	-	-	-	-	-	-	-	-	29	143	172
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	19	87	43	29	-	20	-	-	-	-	300	500
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	-	0	-	-	-	-	-	-	-	-	-	-	2	2
Total Wind	-	-	-	-	-	-	66	178	100	100	19	87	43	29	-	20	-	-	-	29	445	673
CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	-	2.2	-	-	2.7	-	-	-	-	20	25
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1 Total	5.5	37.0	-	19.8	-	-	6.3	-	-	-	-	-	2.2	-	-	2.7	-	-	-	-	69	73
DSM, Class 2, Idaho	1.5	1.8	2.1	3.0	3.6	4.2	4.5	4.8	4.7	5.2	5.2	5.4	6.7	7.3	7.6	7.2	7.5	7.6	7.6	7.1	35	105
DSM, Class 2, Utah	43.3	47.8	41.7	42.9	44.3	47.0	48.2	50.6	52.4	54.9	55.5	59.6	55.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	473	1,067
DSM, Class 2, Wyoming	3.8	4.8	5.1	6.2	6.3	7.2	8.0	8.9	8.9	9.5	11.1	11.8	13.6	17.1	18.2	23.5	25.0	29.3	36.5	39.9	69	295
DSM, Class 2 Total	48.6	54.4	48.9	52.1	54.2	58.4	60.7	64.3	66.0	69.6	71.8	76.8	76.1	84.5	86.0	94.1	89.7	97.0	103.5	109.1	577	1,466
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	24	50
FOT Mead 3rd Qtr HLH	-	168	266	266	-	82	-	-	-	-	-	-	-	-	-	-	-	-	-	-	781	781
FOT Utah 3rd Qtr HLH	-	231	250	69	-	-	103	235	-	250	-	-	-	-	-	-	-	-	-	-	1,138	1,138
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	49	100	75	165	172	-	175	172	91	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	92	-	195	291	422	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	166	-	251	265	298	N/A	100
West																						
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	22	100	100	-	-	-	28	24	100	58	95	46	100	222	672
Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56	-	56
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	-	-	-	200	-	-	22	100	100	-	-	-	28	24	100	58	95	46	156	422	928
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
DSM, Class 2, California	0.7	0.9	0.9	1.2	1.5	1.6	1.7	1.7	1.7	1.8	1.9	1.9	2.3	2.5	2.6	2.3	2.4	2.2	2.5	2.3	14	36
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	8.0	8.4	8.6	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.1	12.4	9.6	8.3	8.7	8.6	9.2	88	191
DSM, Class 2 Total	61.3	62.1	65.5	70.7	72.1	71.2	70.8	63.3	63.4	63.8	65.0	66.2	66.2	66.9	67.3	64.3	54.7	46.9	47.2	47.5	664	1,256
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	16	33
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	26	400	400	400	310	400	400	400	367	400	366	400	400	400	400	400	400	400	400	400	350	373
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	40	20
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	163	-	-	42	N/A	28
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	432	-	-	-	N/A	43
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	43	90	153	330	166	217	300	360	340	N/A	200
Annual Additions, Long Term Resources	136	186	177	780	1,021	157	224	346	384	343	168	240	198	218	187	291	213	248	205	350		
Annual Additions, Short Term Resources	176	1,270	1,476	1,234	710	832	853	985	667	1,000	666	793	890	929	1,215	1,373	1,513	1,621	1,789	1,892		
Total Annual Additions	313	1,457	1,653	2,014	1,730	989	1,077	1,331	1,051	1,343	834	1,033	1,087	1,147	1,402	1,664	1,725	1,870	1,994	2,242		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 6_WM compared to Energy Gateway Case 5_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $607 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(77)	-	-	-	-	-	-	-	-	-	-	-	(29)	(143)	(172)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(19)	(87)	(43)	(29)	-	(20)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	178	200	20	75	35	50	23	110	45	75	39	146	376	995
	Total Wind	-	-	-	-	-	-	94	(178)	78	100	0	(13)	(8)	20	23	90	45	75	39	118	93	483
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1 Total	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	(2.2)	2.2	-	-	-	-	-	-	13	13
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	-	-	-	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Wyoming	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.1)	0	(1)
	DSM, Class 2 Total	-	-	0.1	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	(0.5)	-	(1.1)	1	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	(2)	-	(10)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT Utah 3rd Qtr HLH	-	0	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	20	24	(6)	(2)	49	-	(58)	(54)	27	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(31)	-	32	(6)	6	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	(51)	-	31	41	(24)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(222)	(672)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(56)	-	(56)
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(156)	(222)	(728)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 2, Washington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(2)	(1)	(1)	-	(6)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	-	7	-	0	-	-	-	-	-	-	-	-	-	1	0
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(21)	20	-	23	0	N/A	2
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(19)	(22)	6	-	55	(20)	(2)	1	1	N/A	(0)
	Annual Additions, Long Term Resources	-	(0)	0	-	-	-	100	(200)	(22)	7	0	(13)	(10)	(5)	(1)	(11)	(17)	(25)	(10)	(43)		
	Annual Additions, Short Term Resources	-	0	-	-	-	-	-	7	7	-	0	0	2	0	0	1	2	4	5	10		
	Total Annual Additions	-	(0)	0	-	-	-	100	(193)	(15)	7	0	(13)	(8)	(5)	(1)	(11)	(15)	(21)	(5)	(33)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 7_WM compared to Energy Gateway Case 5_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR **$630 million**

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(77)	-	-	-	-	-	-	-	-	-	-	-	(29)	(143)	(172)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(19)	(87)	(43)	(29)	-	(20)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	178	200	20	75	35	50	23	111	48	73	48	159	376	1,018
	Total Wind	-	-	-	-	-	-	94	(178)	78	100	0	(13)	(8)	20	23	90	48	73	48	130	93	506
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1 Total	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	(2.2)	2.2	-	-	-	-	-	-	13	13
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	-	-	-	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Wyoming	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.1)	0	(1)
	DSM, Class 2 Total	-	-	0.1	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	(0.5)	-	(1.1)	1	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	(2)	-	(10)
	FOT Utah 3rd Qtr HLH	-	0	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	20	24	(6)	(2)	39	-	(56)	(45)	27	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(13)	-	94	(21)	(60)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	(59)	-	(31)	64	24	N/A	-
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(222)	(672)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(56)	-	(56)
	Total Wind	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(156)	(222)	(728)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(2)	(1)	(1)	-	(7)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	-	7	-	0	-	-	-	-	-	-	-	-	-	1	0
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(21)	21	-	7	0	N/A	1
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(19)	(22)	6	-	56	(20)	(2)	1	1	N/A	0
	Annual Additions, Long Term Resources	-	(0)	0	-	-	-	100	(200)	(22)	7	0	(13)	(10)	(5)	(1)	(11)	(15)	(27)	(1)	(30)		
	Annual Additions, Short Term Resources	-	0	-	-	-	-	-	7	7	-	0	0	2	0	0	1	2	4	5	10		
	Total Annual Additions	-	(0)	0	-	-	-	100	(193)	(15)	7	0	(13)	(8)	(5)	(1)	(10)	(12)	(22)	5	(20)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 8_WM compared to Energy Gateway Case 5_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $668 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(77)	-	-	-	-	-	-	-	-	-	-	-	(29)	(143)	(172)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(19)	(87)	(43)	(29)	-	(20)	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	178	200	20	75	35	50	29	108	52	69	59	173	376	1,045
	Total Wind	-	-	-	-	-	-	94	(178)	78	100	0	(13)	(8)	20	29	88	52	69	59	144	93	534
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1 Total	-	(0.0)	-	-	-	-	5.4	-	-	7.3	-	-	(2.2)	2.2	-	-	-	-	-	-	13	13
	DSM, Class 2, Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.5)	-	-	-	(1)
	DSM, Class 2, Utah	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Wyoming	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.1)	0	(1)
	DSM, Class 2 Total	-	-	0.1	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	(0.5)	-	(1.1)	1	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	(2)	-	(10)
	FOT Utah 3rd Qtr HLH	-	0	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	20	24	(6)	20	46	-	(53)	(31)	(19)	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(90)	-	16	(21)	95	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(14)	-	44	56	(67)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(100)	(222)	(672)
	Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(56)	-	(56)
	Total Wind	-	-	-	-	-	-	-	(22)	(100)	(100)	-	-	-	(28)	(24)	(100)	(58)	(95)	(46)	(156)	(222)	(728)
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, California	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	(0.3)	-	-	(0)
	DSM, Class 2 Total	-	-	-	-	-	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	(0.3)	-	-	(0)
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(2)	(1)	(1)	-	(7)
	FOT MidColumbia 3rd Qtr HLH	-	-	-	-	-	-	-	-	7	-	0	-	-	-	-	-	-	-	-	-	1	0
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	21	-	-	0	N/A	2
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	(19)	(22)	6	-	56	(21)	(2)	1	1	N/A	0
	Annual Additions, Long Term Resources	-	(0)	0	-	-	-	100	(200)	(22)	7	0	(13)	(10)	(5)	4	(13)	(11)	(30)	9	(16)		
	Annual Additions, Short Term Resources	-	0	-	-	-	-	-	7	7	-	0	0	2	0	0	1	2	4	6	10		
	Total Annual Additions	-	(0)	0	-	-	-	100	(193)	(15)	7	0	(13)	(8)	(5)	4	(12)	(9)	(26)	15	(6)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 9_WM

PVRR $45,406 million

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource sum, FOT Average 10 Year	20 Year *
East																						
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	66	98	35	-	-	-	-	-	-	-	-	-	-	-	200	200
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	18	88	43	51	-	-	-	-	-	29	300	529
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	0	0	-	-	-	-	-	-	-	-	-	-	2	2
Total Wind	-	-	-	-	-	-	66	200	135	100	18	88	43	51	-	-	-	-	-	29	502	731
CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	-	0.2	2.0	-	2.7	-	-	-	-	20	25
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	8.2	-	-	-	-	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	14	14
DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1 Total	5.5	40.0	-	19.8	-	-	11.6	-	-	-	-	-	0.2	2.0	-	2.7	-	-	-	-	77	82
DSM, Class 2, Idaho	1.5	1.8	2.0	2.8	3.4	3.9	4.5	4.8	4.7	5.1	5.2	5.4	6.5	7.0	7.3	6.8	7.2	6.8	7.1	6.5	34	100
DSM, Class 2, Utah	43.3	46.6	39.0	40.1	41.4	45.8	47.0	49.1	51.1	53.5	54.2	58.1	54.4	56.4	57.9	61.3	55.4	58.2	57.3	62.1	457	1,032
DSM, Class 2, Wyoming	3.5	4.8	5.1	6.1	6.2	7.1	8.0	8.9	8.9	9.5	10.9	11.8	13.6	16.7	17.8	23.0	24.5	28.8	35.9	38.9	68	290
DSM, Class 2 Total	48.3	53.2	46.1	49.0	51.0	56.8	59.5	62.8	64.7	68.1	70.3	75.3	74.5	80.1	83.0	91.2	87.1	93.8	100.3	107.5	559	1,422
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	24	50
FOT Mead 3rd Qtr HLH	-	168	266	266	-	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	787	787
FOT Utah 3rd Qtr HLH	-	229	250	71	-	-	105	236	-	250	-	-	-	-	-	-	-	-	-	-	1,141	1,141
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	144	256	86	236	233	45	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	83	287	563	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	39	242	281	389	N/A	100
West																						
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	65	100	-	-	-	6	46	100	58	97	100	100	165	671
Wind, Oregon, 29% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	-	-	-	200	-	-	-	65	100	-	-	-	6	46	100	58	97	100	100	365	871
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
DSM, Class 2, California	0.7	0.8	0.8	1.1	1.3	1.6	1.7	1.7	1.6	1.7	1.8	1.9	2.2	2.4	2.5	2.2	2.3	2.2	2.2	2.0	13	35
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	7.7	8.0	8.6	8.5	8.6	8.6	8.8	9.1	9.3	9.6	10.7	11.7	11.4	12.1	12.4	9.6	8.3	8.7	8.6	9.0	87	189
DSM, Class 2 Total	60.9	61.6	65.4	70.3	71.5	71.1	70.7	63.2	63.2	63.7	64.8	65.9	66.0	66.8	67.2	64.2	54.6	46.9	46.9	47.0	662	1,252
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	-	16	32
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	27	400	400	400	364	400	400	400	366	400	367	400	400	400	400	400	400	335	114	-	356	339
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	24	74	132	95	189	115	187	184	N/A	100
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	377	-	-	623	N/A	100
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	95	171	163	249	285	68	327	407	234	N/A	200
Annual Additions, Long Term Resources	136	188	174	777	1,017	156	228	344	383	341	165	239	193	215	206	268	210	247	256	1,014		
Annual Additions, Short Term Resources	177	1,268	1,476	1,237	714	838	855	986	666	1,000	667	795	896	936	1,225	1,386	1,527	1,638	1,808	2,338		
Total Annual Additions	312	1,456	1,650	2,013	1,732	993	1,083	1,330	1,048	1,341	832	1,034	1,089	1,151	1,431	1,653	1,737	1,885	2,064	3,352		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 10_WM compared to Energy Gateway Case 9_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $591 million

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Sum, FOT Avg 10 Year	Resource Sum, FOT Avg 20 Year *
		Capacity (MW)																					
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(51)	-	-	-	-	-	43	(300)	(457)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	24	100	45	67	37	93	505	1,023
	Total Wind	-	-	-	-	-	-	94	(93)	65	100	(4)	(17)	(17)	(11)	24	100	45	67	37	136	165	526
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(3.6)	-	-	-	8.8	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(3.6)	-	-	-	15.1	12.0	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	24	24
	DSM, Class 2, Idaho	-	-	-	-	0.2	0.3	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	-	2.0	2.7	2.8	4.0	2.4	2.4	3.0	4.4	16.0	-	-	-	-	-	-	-	-	-	-	40	40
	DSM, Class 2, Wyoming	0.3	-	0.0	0.1	0.1	0.1	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	2.0	2.7	2.9	4.3	2.8	2.4	3.0	4.4	16.3	-	-	-	-	-	-	-	-	-	-	41	41
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(3)	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	FOT Utah 3rd Qtr HLH	-	2	-	(9)	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	(11)	65	(5)	(6)	(44)	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(12)	56	(38)	(5)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	119	24	19	(230)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Total Wind	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	0.1	0.1	0.1	0.2	-	-	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Washington	0.2	0.4	-	0.4	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 2 Total	0.2	0.4	0.1	0.5	0.5	0.1	0.1	0.2	0.1	0.1	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)	(2)	(1)	-	-	(6)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	32	-	-	-	14	-	0	-	-	-	-	-	-	65	(50)	-	5	3
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(11)	76	(6)	(19)	0	(40)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(236)	-	-	236	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	12	(76)	5	(37)	65	(96)	79	49	N/A	0
	Annual Additions, Long Term Resources	0	(1)	3	10	(45)	22	98	(83)	5	17	(4)	(17)	(17)	(17)	(22)	(1)	(15)	(34)	(66)	33		
	Annual Additions, Short Term Resources	(0)	2	(0)	(9)	32	11	14	14	14	-	0	-	0	(0)	0	1	1	3	4	5		
	Total Annual Additions	0	1	3	1	(13)	33	112	(69)	18	17	(4)	(17)	(17)	(17)	(22)	(1)	(14)	(31)	(62)	38		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 11_WM compared to Energy Gateway Case 9_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $612 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(51)	-	-	-	-	-	(29)	(300)	(529)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	24	100	47	67	37	153	505	1,085
	Total Wind	-	-	-	-	-	-	94	(93)	65	100	(4)	(17)	(17)	(11)	24	100	47	67	37	124	165	515
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(3.6)	-	-	-	8.8	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(3.6)	-	-	-	15.1	12.0	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	24	24
	DSM, Class 2, Idaho	-	-	-	-	0.2	0.3	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	-	2.0	2.7	2.8	4.0	2.4	2.4	3.0	4.4	16.0	-	-	-	-	-	-	-	-	-	-	40	40
	DSM, Class 2, Wyoming	0.3	-	0.0	0.1	0.1	0.1	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	2.0	2.7	2.9	4.3	2.8	2.4	3.0	4.4	16.3	-	-	-	-	-	-	-	-	-	-	41	41
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(3)	(3)	-	(11)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	FOT Utah 3rd Qtr HLH	-	2	-	(9)	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	21	42	7	(27)	(44)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	44	(38)	5	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	144	23	40	(244)	N/A	(0)
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Total Wind	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	0.1	0.1	0.1	0.2	-	-	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Washington	0.2	0.4	-	0.4	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 2 Total	0.2	0.4	0.1	0.5	0.5	0.1	0.1	0.2	0.1	0.1	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(2)	(2)	(2)	(1)	-	-	(7)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	32	-	-	-	14	-	0	-	-	-	-	-	-	65	(44)	-	5	3
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(11)	76	(6)	(19)	0	(40)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(236)	-	-	236	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	12	(76)	5	(37)	64	(96)	74	54	N/A	0
	Annual Additions, Long Term Resources	0	(1)	3	10	(45)	22	98	(83)	5	17	(4)	(17)	(17)	(17)	(22)	(2)	(16)	(34)	(66)	21		
	Annual Additions, Short Term Resources	(0)	2	(0)	(9)	32	11	14	14	14	-	0	-	0	(0)	0	1	3	4	6	7		
	Total Annual Additions	0	1	3	1	(13)	33	112	(69)	18	17	(4)	(17)	(17)	(17)	(22)	(1)	(14)	(30)	(60)	28		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 12_WM compared to Energy Gateway Case 9_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $651 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(66)	(98)	(35)	-	-	-	-	-	-	-	-	-	-	-	(200)	(200)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(18)	(88)	(43)	(51)	-	-	-	-	-	(29)	(300)	(529)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	24	100	47	67	37	153	505	1,085
	Total Wind	-	-	-	-	-	-	94	(93)	65	100	(4)	(17)	(17)	(11)	24	100	47	67	37	124	165	515
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(3.6)	-	-	-	8.8	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	24	24
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(3.6)	-	-	-	15.1	12.0	-	-	-	-	-	(0.2)	0.2	-	-	-	-	-	-	24	24
	DSM, Class 2, Idaho	-	-	-	-	0.2	0.3	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	-	2.0	2.7	2.8	4.0	2.4	2.4	3.0	4.4	16.0	-	-	-	-	-	-	-	-	-	-	40	40
	DSM, Class 2, Wyoming	0.3	-	0.0	0.1	0.1	0.1	-	-	-	0.2	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.3	2.0	2.7	2.9	4.3	2.8	2.4	3.0	4.4	16.3	-	-	-	-	-	-	-	-	-	-	41	41
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(3)	(3)	-	(11)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	FOT Utah 3rd Qtr HLH	-	2	-	(9)	-	-	14	14	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	120	(29)	(50)	(44)	-	0
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11)	70	(38)	(21)	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62	207	27	93	(389)	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Total Wind	-	-	-	-	-	-	-	-	(65)	(100)	-	-	-	(6)	(46)	(100)	(58)	(97)	(100)	(100)	(165)	(671)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	6.5	-	0.3	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	0.1	0.1	0.1	0.2	-	-	0.1	0.0	0.1	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Washington	0.2	0.4	-	0.4	0.4	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 2 Total	0.2	0.4	0.1	0.5	0.5	0.1	0.1	0.2	0.1	0.1	-	-	-	-	-	-	-	-	-	-	2	2
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(2)	(2)	(2)	(1)	-	-	(7)
	FOT MidColumbia 3rd Qtr HLH	(0)	-	-	-	32	-	-	-	14	-	0	-	-	-	-	-	-	65	(44)	-	5	3
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	(11)	76	(6)	(25)	0	(34)	0	0	N/A	(0)
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(377)	-	-	377	N/A	0
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	12	(76)	5	(37)	65	(96)	44	84	N/A	0
	Annual Additions, Long Term Resources	0	(1)	3	10	(45)	22	98	(83)	5	17	(4)	(17)	(17)	(17)	(22)	(2)	(16)	(34)	(66)	21		
	Annual Additions, Short Term Resources	(0)	2	(0)	(9)	32	11	14	14	14	-	0	-	0	(0)	0	1	3	4	6	7		
	Total Annual Additions	0	1	3	1	(13)	33	112	(69)	18	17	(4)	(17)	(17)	(17)	(22)	(1)	(14)	(30)	(60)	28		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 13_WM

PVRR $46,392 million

	Capacity (MW)																				Resource sum, FOT Average	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
Thermal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2	-	-	-	-	-	-	-	-	-	51	53
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	67	-	-	-	-	-	-	-	-	-	-	-	-	79	67	146
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	100	100	100	21	88	43	48	-	-	-	-	-	-	300	500
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	2	-	0	-	-	-	-	-	-	-	-	-	-	2	2
Total Wind	-	-	-	-	-	-	67	102	100	100	21	88	43	48	-	-	-	-	-	79	368	648
CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
DSM, Class 1, Utah-Coolkeeper	5.5	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	19.8	-	-	-	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	20	25
DSM, Class 1, Utah-Curtailment	-	21.5	-	-	-	-	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	3.7	-	-	-	-	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
DSM, Class 1, Wyoming-Curtailment	-	5.4	-	-	-	-	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1 Total	5.5	35.5	-	19.8	-	-	10.7	-	-	-	-	2.2	-	-	-	2.7	-	-	-	-	71	76
DSM, Class 2, Idaho	1.5	1.9	2.1	3.0	3.6	4.2	4.6	4.9	4.9	5.4	5.4	5.6	7.0	7.6	8.0	7.6	8.0	7.6	7.6	7.1	36	108
DSM, Class 2, Utah	44.4	48.6	41.7	42.9	44.3	48.2	49.4	50.6	52.4	54.9	57.2	61.5	57.8	60.1	60.2	63.5	57.2	60.1	59.3	62.1	477	1,076
DSM, Class 2, Wyoming	3.8	4.8	5.2	6.2	6.3	7.2	8.0	9.1	9.1	9.7	11.3	12.0	13.9	17.2	18.6	24.0	25.6	30.1	37.5	39.9	69	299
DSM, Class 2 Total	49.7	55.3	49.0	52.1	54.2	59.6	62.0	64.6	66.3	70.0	73.9	79.1	78.7	84.9	86.8	95.1	90.8	97.8	104.4	109.1	583	1,483
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	24	50
FOT Mead 3rd Qtr HLH	-	168	266	266	-	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	780	780
FOT Utah 3rd Qtr HLH	-	231	250	69	-	-	96	235	-	250	-	-	-	-	-	-	-	-	-	-	1,131	1,131
FOT Mona / NUB	-	-	150	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	225	263
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	69	72	104	83	145	126	86	221	26	69	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	39	196	269	492	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	158	89	250	248	223	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Thermal Plant Turbine Upgrades	-	-	4	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	98	100	100	-	-	-	9	45	100	92	80	98	100	298	821
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	-	-	-	200	-	-	98	100	100	-	-	-	9	45	100	92	80	98	100	498	1,021
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
DSM, Class 1, Calilifornia-DLC-Irrigation	-	-	5.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Oregon-Curtailment	-	-	17.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon-DLC-Irrigation	-	-	13.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
DSM, Class 1, Oregon-DLC-Residential	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Washington-DLC-Irrigation	-	-	2.1	-	-	-	6.4	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
DSM, Class 1, Washington-DLC-Residential	-	-	1.2	-	-	-	3.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1 Total	-	-	42.8	-	-	-	10.0	-	-	-	-	-	-	-	-	-	-	-	-	-	53	53
DSM, Class 2, California	0.7	0.9	0.9	1.2	1.5	1.6	1.7	1.7	1.7	1.8	1.9	1.9	2.6	2.8	2.9	2.6	2.7	2.5	2.5	2.3	14	39
DSM, Class 2, Oregon	52.6	52.8	56.0	60.7	61.7	60.8	60.3	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	52.4	44.0	36.1	36.1	36.1	562	1,028
DSM, Class 2, Washington	8.0	8.4	9.0	8.8	8.9	8.7	8.9	9.2	9.4	9.6	10.8	11.8	11.5	12.5	12.8	9.9	8.5	8.9	8.9	9.3	89	194
DSM, Class 2 Total	61.3	62.1	65.9	70.8	72.1	71.2	70.9	63.3	63.4	63.8	65.0	66.2	66.5	67.7	68.1	64.9	55.2	47.5	47.5	47.6	665	1,261
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	-	16	32
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	26	400	400	400	309	400	400	400	367	400	295	400	400	400	400	400	400	266	276	270	350	350
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern Cal. 3rd Qtr HLH	-	50	50	50	50	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	40	20
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	134	189	-	186	195	N/A	70
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210	-	162	438	N/A	81
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	16	80	140	330	244	191	379	310	311	N/A	200
Annual Additions, Long Term Resources	138	186	177	780	1,021	158	230	346	384	343	172	246	198	219	209	272	248	234	258	1,066		
Annual Additions, Short Term Resources	176	1,270	1,476	1,234	709	831	846	985	667	1,000	664	787	884	922	1,208	1,365	1,504	1,611	1,778	2,299		
Total Annual Additions	313	1,456	1,653	2,014	1,730	989	1,076	1,331	1,051	1,343	836	1,033	1,082	1,141	1,417	1,638	1,751	1,846	2,036	3,365		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 14_WM compared to Energy Gateway Case 13_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $587 million

	Resource	Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(67)	(146)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(21)	(88)	(43)	(48)	-	-	-	-	-	84	(300)	(416)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	105	200	200	15	71	26	39	176	-	-	134	-	44	505	1,010
	Total Wind	-	-	-	-	-	-	93	5	100	100	(6)	(17)	(17)	(8)	176	-	-	134	-	49	299	609
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(1.6)	-	-	-	7.4	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(1.6)	-	-	-	13.6	16.9	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	29	29
	DSM, Class 2, Idaho	0.1	-	-	-	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	0.7	-	1.1	1.1	1.1	-	-	3.4	-	9.2	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 2, Wyoming	0.0	-	-	-	-	0.1	0.1	0.1	0.1	0.2	-	-	-	(0.1)	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.8	-	1.1	1.1	1.2	0.2	0.2	3.7	0.3	9.3	-	-	-	(0.1)	-	-	-	-	-	-	18	18
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(2)	-	(5)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	19
	FOT Utah 3rd Qtr HLH	-	1	-	(7)	-	-	18	15	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(19)	30	80	78	42	25	(86)	(65)	(23)	(61)	-	-
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	(39)	(13)	(12)	50	N/A	(0)
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)	(79)	(89)	30	(21)	181	N/A	-
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Total Wind	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	-	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	0
	DSM, Class 2, Washington	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	0.3	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(3)
	FOT MidColumbia 3rd Qtr HLH	(1)	-	-	-	36	-	-	-	14	-	(202)	(12)	-	-	-	-	-	134	124	(270)	5	(9)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	26	0	46	0	(11)	N/A	9
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	215	-	68	(163)	N/A	16
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	222	(16)	(80)	(77)	(45)	(26)	(0)	(130)	(133)	286	N/A	0
	Annual Additions, Long Term Resources	1	(1)	1	7	(49)	17	101	(89)	0	16	(6)	(19)	(15)	(17)	132	(101)	(93)	53	(101)	(54)		
	Annual Additions, Short Term Resources	(1)	1	(0)	(7)	36	19	18	15	14	-	(0)	2	0	0	0	0	1	1	2	11		
	Total Annual Additions	0	(0)	1	0	(13)	36	118	(74)	15	16	(6)	(17)	(15)	(17)	132	(100)	(92)	54	(99)	(43)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 15_WM compared to Energy Gateway Case 13_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $564 million

		Capacity (MW)																				Resource Sum, FOT Avg	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																							
	Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(67)	(146)
	Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(21)	(88)	(43)	(48)	-	-	-	-	-	-	(300)	(500)
	Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	-	(0)	-	42	200	200	200	200	200	200	200	18	(2)	1,458
	Total Wind	-	-	-	-	-	-	93	(102)	(100)	(100)	(21)	(47)	157	152	200	200	200	200	200	(61)	(208)	972
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Utah-DLC-Residential	-	(2.2)	-	-	-	7.4	23.8	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	(2.2)	-	-	-	13.6	17.5	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	29	29
	DSM, Class 2, Idaho	0.1	-	-	-	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 2, Utah	0.7	0.8	1.1	1.1	1.1	-	-	2.6	-	9.2	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 2, Wyoming	0.0	-	-	-	-	0.1	0.1	0.1	0.1	0.2	-	-	-	(0.1)	-	-	-	-	-	-	1	1
	DSM, Class 2 Total	0.8	0.8	1.1	1.1	1.2	0.2	0.2	2.9	0.3	9.3	-	-	-	(0.1)	-	-	-	-	-	-	18	18
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	-	(8)
	FOT Mead 3rd Qtr HLH	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	19
	FOT Utah 3rd Qtr HLH	-	1	-	(7)	-	-	17	15	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	(19)	91	80	102	(30)	16	(86)	(104)	(26)	(23)	-	(0)
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	(39)	20	(8)	2	N/A	0
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	7	43	36	39	(80)	(89)	(49)	(68)	160	N/A	0
West																							
	Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Total Wind	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
	Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 2, California	-	-	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	0
	DSM, Class 2, Washington	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 2 Total	-	0.3	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	1
	Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(3)
	FOT MidColumbia 3rd Qtr HLH	(1)	-	-	-	36	-	-	-	14	-	(242)	(80)	(42)	-	-	-	-	134	124	(270)	5	(16)
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	58	-	-	-	52	24	0	84	0	(11)	N/A	21
	Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	215	-	68	(133)	N/A	19
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	203	(16)	(80)	(138)	(61)	(25)	(0)	(83)	(86)	286	N/A	0
	Annual Additions, Long Term Resources	1	(1)	1	7	(49)	17	101	(197)	(200)	(184)	(21)	(49)	159	143	155	99	107	117	99	(164)		
	Annual Additions, Short Term Resources	(1)	1	(0)	(7)	36	19	17	15	14	-	(0)	2	0	0	0	0	1	2	3	12		
	Total Annual Additions	0	(0)	1	0	(13)	36	118	(182)	(185)	(184)	(21)	(47)	159	144	156	100	108	119	102	(152)		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

Energy Gateway Case 16_WM compared to Energy Gateway Case 13_WM

Resource differences from base transmission scenario are shown. PVRR difference indicated as an increase or (decrease).

PVRR $596 million

	Capacity (MW)																				Resource Sum, FOT Avg	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year *
East																						
Wind, Goshen, 29% Capacity Factor	-	-	-	-	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(67)	(146)
Wind, Utah, 29% Capacity Factor	-	-	-	-	-	-	-	(100)	(100)	(100)	(21)	(88)	(43)	(48)	-	-	-	-	-	-	(300)	(500)
Wind, WYNE 35% Capacity Factor	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-	160	160
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	(2)	-	(0)	-	200	200	200	200	200	200	200	200	200	(2)	1,798
Total Wind	-	-	-	-	-	-	93	(102)	(100)	(100)	(21)	112	157	152	200	200	200	200	200	121	(208)	1,312
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	-	-
DSM, Class 1, Utah-Curtailment	-	-	-	-	-	4.9	(4.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, Utah-DLC-Residential	-	(1.6)	-	-	-	7.4	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
DSM, Class 1, Wyoming-Curtailment	-	-	-	-	-	1.4	(1.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1 Total	-	(1.6)	-	-	-	13.6	16.9	-	-	-	-	(2.2)	2.2	-	-	-	-	-	-	-	29	29
DSM, Class 2, Idaho	0.1	-	-	-	0.1	0.1	0.1	0.1	0.1	-	-	-	(0.3)	-	-	-	-	-	-	-	1	0
DSM, Class 2, Utah	0.7	-	1.1	1.1	1.1	-	-	3.4	-	9.2	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 2, Wyoming	0.0	-	-	-	-	0.1	0.1	0.1	0.1	0.2	-	-	-	(0.1)	-	-	-	-	-	-	1	1
DSM, Class 2 Total	0.8	-	1.1	1.1	1.2	0.2	0.2	3.7	0.3	9.3	-	-	(0.3)	(0.1)	-	-	-	-	-	-	18	18
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(3)	(3)	(2)	-	(8)
FOT Mead 3rd Qtr HLH	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	19
FOT Utah 3rd Qtr HLH	-	1	-	(7)	-	-	18	15	-	-	-	-	-	-	-	-	-	-	-	-	26	26
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	114	80	64	86	(52)	(54)	(86)	(87)	5	(69)	-	0
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(39)	(55)	50	48	N/A	(0)
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	31	-	14	8	3	58	(89)	9	73	(109)	N/A	0
West																						
Wind, Yakima, 29% Capacity Factor	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
Total Wind	-	-	-	-	-	-	-	(98)	(100)	(100)	-	-	-	(9)	(45)	(100)	(92)	(80)	(98)	(100)	(298)	(821)
Utility Biomass	-	-	-	-	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(50)	(50)
DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 1, Washington-DLC-Irrigation	-	-	-	6.4	-	-	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1, Washington-DLC-Residential	-	-	-	-	-	3.6	(3.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM, Class 1 Total	-	-	-	6.4	-	3.6	(10.0)	0.3	-	6.5	-	-	-	-	-	-	-	-	-	-	7	7
DSM, Class 2, California	-	-	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	0
DSM, Class 2, Washington	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
DSM, Class 2 Total	-	0.3	-	0.0	0.0	-	-	0.2	0.2	0.2	-	-	(0.3)	-	-	-	-	-	-	-	1	1
Micro Solar - Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(1)	(1)	-	-	(3)
FOT MidColumbia 3rd Qtr HLH	(1)	-	-	-	36	-	-	-	14	-	(205)	(63)	-	-	-	-	-	134	124	(270)	5	(12)
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	(3)	0	57	0	(11)	N/A	11
Growth Resource OR / CA *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	(162)	136	N/A	19
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	61	(16)	(77)	(94)	(21)	3	(0)	(56)	(86)	286	N/A	0
Annual Additions, Long Term Resources	1	(1)	1	7	(49)	17	101	(196)	(200)	(184)	(21)	109	159	143	155	99	107	117	99	18		
Annual Additions, Short Term Resources	(1)	1	(0)	(7)	36	19	18	15	14	-	0	2	0	0	0	1	1	2	4	12		
Total Annual Additions	0	(0)	1	0	(13)	36	118	(181)	(185)	(184)	(21)	112	159	144	156	100	108	119	103	30		

** For the 20 Year column "Growth Stations" are an 10 year average reflecting the available years from 2021-2030.*

APPENDIX D – SYSTEM OPTIMIZER DETAILED MODELING RESULTS

This appendix reports the detailed portfolio resource selection tables for each of the scenario development cases outlined in Chapter 7. These tables are outputs from the System Optimizer model used during portfolio development.

Table D.1 – Resource Name and Description

Resource List	Detailed Description
East Resources	
CCCT F 2x1	Combine Cycle Combustion Turbine F-Machine 2x1 with Duct Firing
CCCT H	Combine Cycle Combustion Turbine H-Machine 1x1 with Duct Firing
CCS Hunter - Unit 3 (Replaces Original Unit)	IRP Carbon Capture & Sequestration Hunter 3
CHP - Biomass	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	Combined Heat and Power - Reciprocating Engine
Coal Plant Turbine Upgrades	Coal Plant Turbine Upgrades
DSM, Class 1, Goshen-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Utah-CoolKeeper	DSM - Class 1 - Utah CoolKeeper
DSM, Class 1, Utah-Curtailment	IRP DSM Class 1 [Bubble] Curtailment
DSM, Class 1, Utah-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Utah-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 1, Utah-Sched Therm Energy Storage	IRP DSM Class 1 [Bubble] Scheduled-Thermal Energy Storage
DSM, Class 1, Wyoming-Curtailment	IRP DSM Class 1 [Bubble] Curtailment
DSM, Class 2, Goshen	DSM, Class 2, Goshen
DSM, Class 2, Utah	DSM, Class 2, Utah
DSM, Class 2, Wyoming	DSM, Class 2, Wyoming
DSM, Class 3, Utah, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Utah, Critical Peak Pricing, Commercial - Industrial
DSM, Class 3, Utah, Demand Buyback, Comm/Indus	DSM, Class 3, Utah, Demand Buyback, Commercial - Industrial
DSM, Class 3, Utah, Real-Time Pricing, Comm/Indus	DSM, Class 3, Utah, Real-Time Pricing, Commercial - Industrial
DSM, Class 3, Utah, Time of Use, Irrigation	DSM, Class 3, Utah, Time of Use, Irrigation
DSM, Class 3, Utah, Time of Use, Residential	DSM, Class 3, Utah, Time of Use, Residential
DSM, Class 3, Wyoming, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Wyoming, Critical Peak Pricing, Comm/Indus
DSM, Class 3, Wyoming, Demand Buyback, Comm/Indus	DSM, Class 3, Wyoming, Demand Buyback, Comm/Indus
DSM, Class 3, Wyoming, Real-Time Pricing, Comm/Indus	DSM, Class 3, Wyoming, Real-Time Pricing, Comm/Indus
DSM, Class 3, Wyoming, Time of Use, Irrigation	DSM, Class 3, Wyoming, Time of Use, Irrigation
FOT Mead 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product
FOT Mona-3 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product
FOT Mona-4 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product

Resource List	Detailed Description
FOT Utah 3rd Qtr HLH	Front Office Transaction - 3rd Quarter HLH Product
Geothermal, Blundell 3	Geothermal (East-Blundell, East-Greenfield, West-Greenfield)
Geothermal, Greenfield	Geothermal (East-Blundell, East-Greenfield, West-Greenfield)
Growth Resource Goshen	Growth Resource (Goshen)
Growth Resource Utah North	Growth Resource (Utah North)
Growth Resource Wyoming	Growth Resource (Wyoming)
Micro Solar - Water Heater	Micro Solar - Solar Water Heating
Nuclear	Nuclear
SCCT Aero Utah	Simple Cycle Combustion Turbine Aero
Wind, Wyoming NE, 35% Capacity Factor	Wind, Project II
Wind, Utah, 29% Capacity Factor	Wind, Utah, 29% Capacity Factor
Wind, Wyoming, 35% Capacity Factor	[Bubble] Wind 35% Capacity Factor
West Resources	
CCS Bridger - Unit 1 (Replaces Original Unit)	IRP Carbon Capture & Sequestration Bridger 1 (Replaces Original Unit)
CCS Bridger - Unit 2 (Replaces Original Unit)	IRP Carbon Capture & Sequestration Bridger 2 (Replaces Original Unit)
CHP - Biomass	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	Combined Heat and Power - Reciprocating Engine
Coal Plant Turbine Upgrades	Coal Plant Turbine Upgrades
Distribution Energy Efficiency, Walla Walla	Distribution Energy Efficiency, Walla Walla
Distribution Energy Efficiency, Yakima	Distribution Energy Efficiency, Yakima
DSM, Class 1, Oregon/California-Curtailment	IRP DSM Class 1 [Bubble] Curtailment
DSM, Class 1, Oregon/California-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Oregon/California-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 1, Oregon/California-DLC-Water Heater	IRP DSM Class 1 [Bubble] Direct Load Control-Water Heater
DSM, Class 1, Walla Walla-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Walla Walla-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 1, Yakima-DLC-Irrigation	IRP DSM Class 1 [Bubble] Direct Load Control-Irrigation
DSM, Class 1, Yakima-DLC-Residential	IRP DSM Class 1 [Bubble] Direct Load Control-Residential
DSM, Class 2, Oregon/California	DSM, Class 2, - Oregon/California
DSM, Class 2, Walla Walla	DSM, Class 2, - Walla Walla

Resource List	Detailed Description
DSM, Class 2, Yakima	DSM, Class 2, - Yakima
DSM, Class 3, California, Time of Use, Irrigation	DSM, Class 3, California, Time of Use, Irrigation
DSM, Class 3, Goshen, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Goshen, Critical Peak Pricing, Commercial - Industrial
DSM, Class 3, Goshen, Time of Use, Irrigation	DSM, Class 3, Goshen, Time of Use, Irrigation
DSM, Class 3, Oregon, Critical Peak Pricing, Comm/Indus	DSM, Class 3, Oregon, Critical Peak Pricing, Comm/Indus
DSM, Class 3, Oregon, Time of Use, Irrigation	DSM, Class 3, Oregon, Time of Use, Irrigation
DSM, Class 3, Walla Walla, Time of Use, Irrigation	DSM, Class 3, Walla Walla, Time of Use, Irrigation
DSM, Class 3, Yakima, Time of Use, Irrigation	DSM, Class 3, Yakima, Time of Use, Irrigation
FOT COB 3rd Qtr HLH	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
FOT MidColumbia 3rd Qtr HLH	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
FOT South Central Oregon/Northern California 3rd Qtr HLH	Front Office Transaction - [Bubble] 3rd Quarter HLH Product
Growth Resource Oregon/California	Growth Resource (Oregon/California)
Growth Resource Walla Walla	Growth Resource (Walla Walla)
Growth Resource Yakima	Growth Resource (Yakima)
Micro Solar - Photovoltaic	Micro Solar - Photovoltaic
Oregon Solar Cap Standard	Oregon Solar Capacity Standard
Oregon Solar Pilot	Oregon Solar Pilot program
Utility Biomass	Utility Biomass
Utility Scale Solar - Photovoltaic	Utility Scale Solar - Photovoltaic
Wind, Goshen, 29% Capacity Factor	Wind, Goshen, 29% Capacity Factor
Wind, Oregon, 29% Capacity Factor	Wind, Oregon, 29% Capacity Factor
Wind, Walla Walla, 29% Capacity Factor	Wind-Walla Walla, 29% Capacity Factor
Wind, Walla Walla, 29% Capacity Factor	Wind-Walla Walla, 29% Capacity Factor
Wind, Washington, 29% Capacity Factor	Wind, Washington, 29% Capacity Factor
Wind, Yakima, 29% Capacity Factor	Wind-Yakima, 29% Capacity Factor
Wind, Yakima, 29% Capacity Factor	Wind-Yakima, 29% Capacity Factor

Notes on Market and Topology Bubbles:

Please see the Transmission Topology chart in Chapter 7 for the “bubbles” used for location of modeled resource options.

Portfolio Case Build Tables

This section provides the System Optimizer portfolio build tables for each of the case scenarios as described in the portfolio development section of Chapter 7.

- Core Case Studies – Case 1 to 19
- Hard Cap Studies – Case 15 to 18
- Business Plan Case Study – Case 19
- Coal Utilization Sensitivity Case Studies – Case 20 to 24
- Load Forecasting Sensitivity Case Studies – Case 25 to 27
- Renewable Resource Sensitivity Cases – 28 to 30a
- Demand-side Management Sensitivity Cases – 31 to 33

Table D.2 – Total Portfolio Cumulative Capacity Additions by Case and Resource Type, 2011 – 2030

20-year resource totals (MW capacity)

Case	**Core 1**	**Core 2**	**Core 3**	**Core 4**	**Core 5**	**Core 6**	**Core 7**	**Core 8**	**Core 9**	**Core 9a**	**Core 10**	**Core 11**	**Core 12**	**Core 13**	**Core 14**	**Core 15**	**Core 16**	**Core 17**	**Core 18**	**Core 19**
CO_2 cost	None	None	Medium	High	Low to very high	Low to very high	Medium	High	Low to very high	Low to very high	Low to very high	Medium	High	Low to very high	Low to very high	Medium	Medium	Medium	Medium	Business Plan (BP)
Natural gas cost	Medium	Medium	Low	Low	Low	Low	Medium	Medium	Medium	Medium	Medium	High	High	High	High	Low	Medium	High	Medium	BP
Transmission scenario [1]	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Resource																				
East																				
Coal																				
Coal Plant Turbine Upgrades	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
CCS																				
CCS Hunter - Unit 3 (Replaces Original Unit)	0	0	0	280	280	280	0	280	280	280	280	0	280	280	280	280	280	280	280	0
CHP																				
CHP - Biomass	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	10
CHP - Reciprocating Engine	4	6	5	2	5	2	2	2	2	3	2	3	2	3	5	6	2	2	2	0
DSM, Class 1	95	102	97	102	97	96	100	99	99	92	99	102	99	102	101	97	92	99	86	102
DSM, Class 2	1,300	1,361	1,384	1,441	1,431	1,402	1,380	1,457	1,461	1,460	1,451	1,553	1,527	1,562	1,599	1,404	1,446	1,568	1,463	1,532
Gas																				
CCCT F 2x1	1,222	1,222	1,222	1,222	1,819	1,819	1,222	1,222	1,819	1,819	1,819	1,222	1,222	1,222	625	1,222	1,222	1,222	1,222	1,819
CCCT H	475	475	475	1,425	2,375	2,375	475	475	1,425	1,425	950	0	0	0	475	1,425	1,900	0	2,375	0
SCCT Aero Utah	0	0	0	0	0	0	0	0	0	0	118	0	0	0	118	0	0	0	0	0
Geothermal																				
Geothermal, Blundell 3	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Geothermal, Greenfield	35	0	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	0
Nuclear																				
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	1,600	1,600	0	0	1,600	0	0
Solar																				
Micro Solar - Water Heater	28	24	37	39	36	26	29	34	37	23	26	37	42	45	45	37	34	45	34	0
Wind																				
Wind, Wyoming NE, 35% Capacity Factor	0	0	0	0	0	160	160	0	0	0	160	0	160	0	160	0	0	160	0	160
Wind, WY 35% CF	143	0	139	136	227	145	55	50	500	418	600	0	1,800	1,600	2,000	139	50	2,240	308	1,100
FOT (20yr Average)																				
FOT Mead 3rd Qtr HLH	40	37	36	36	36	40	36	36	36	40	37	40	40	40	45	38	38	40	36	40
FOT Mona-3 3rd Qtr HLH	255	255	255	255	210	210	255	255	240	240	240	255	255	255	255	255	246	255	195	255
FOT Utah 3rd Qtr HLH	57	54	54	52	54	60	44	52	53	56	51	50	50	50	71	53	53	50	52	60
FOT Mona-4 3rd Qtr HLH	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Growth Resource (10yr Average)																				
Growth Resource Goshen	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Growth Resource Utah North	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	46	10	100	0	100
Growth Resource Wyoming	100	100	100	100	100	100	100	100	100	100	100	100	100	100	80	100	97	100	21	100
West																				
Coal																				
Coal Plant Turbine Upgrades	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
CCS																				
CCS Bridger - Unit 1 (Replaces Original Unit)	0	0	0	227	227	227	0	227	227	227	227	0	227	227	227	227	227	227	227	0
CCS Bridger - Unit 2 (Replaces Original Unit)	0	0	0	216	216	216	0	216	216	216	216	0	216	216	216	216	216	216	216	0
CHP																				
CHP - Biomass	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	42
CHP - Reciprocating Engine	2	3	1	1	1	1	1	1	1	1	1	1	1	1	2	2	1	0	1	0
DSM, Class 1	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	56	60	56	60
DSM, Class 2	1,226	1,239	1,239	1,257	1,253	1,247	1,243	1,260	1,260	1,260	1,258	1,266	1,269	1,270	1,269	1,251	1,259	1,274	1,261	1,272
Geothermal																				
Geothermal, Greenfield	70	0	105	105	70	105	70	140	245	280	490	420	420	420	408	105	140	420	105	0
Other																				
Utility Biomass	50	50	0	0	0	0	0	0	0	50	50	50	50	50	50	0	0	50	0	0
Solar																				
Oregon Solar Cap Standard	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Oregon Solar Pilot	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Micro Solar - Water Heater	15	16	18	21	20	15	19	20	21	12	18	24	29	30	29	16	19	31	20	0
Wind																				
Wind, Yakima, 29% CF	0	0	0	0	0	0	0	0	0	0	0	100	100	100	200	0	0	100	100	0
Wind, Walla Walla, 29% CF	0	0	0	0	0	0	0	0	0	0	0	0	100	0	0	0	0	100	0	0
FOT (20yr Average)																				
FOT COB 3rd Qtr HLH	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
FOT MidColumbia 3rd Qtr HLH	372	370	337	231	243	248	354	279	275	270	275	355	333	315	313	315	280	332	197	368
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	22	22	23	23	23	23	24	23	23	22	23	22	22	22	22	23	23	22	22	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	39	40	18	18	18	18	18	18	18	18	20	17	13	16	18	33	37	35	30	20
Growth Resource (10yr Average)																				
Growth Resource Walla Walla	100	78	100	100	0	0	48	100	23	23	47	20	73	18	38	0	0	0	0	7
Growth Resource Oregon / California	4	68	100	100	50	38	41	100	45	14	76	29	56	0	0	0	0	20	0	0
Growth Resource Yakima	119	100	100	200	120	129	200	200	200	200	200	200	200	200	200	100	100	100	100	166

1. Transmission Scenario is referencing the scenario as described in the Portfolio Case Development paper.

Table D.3 – Core Case System Optimizer PVRR Results

PVRR by Case ($ millions)

Core Case	CO_2 Policy Type	CO_2 cost	Natural gas cost	Renewable PTC	RPS	PVRR
Case-01	None	None	Medium	Extension to 2015	Current RPS	$30,936
Case-02	None	None	Medium	Extension to 2015	None	$30,884
Case-03	CO_2 Tax	Medium	Low	Extension to 2015	Current RPS	$39,581
Case-04	CO_2 Tax	High	Low	Extension to 2015	Current RPS	$44,346
Case-05	CO_2 Tax	Low to very high	Low	Extension to 2015	Current RPS	$40,058
Case-06	CO_2 Tax	Low to very high	Low	Extension to 2020	Current RPS	$39,814
Case-07	CO_2 Tax	Medium	Medium	Extension to 2015	Current RPS	$40,772
Case-08	CO_2 Tax	High	Medium	Extension to 2015	Current RPS	$46,015
Case-09	CO_2 Tax	Low to very high	Medium	Extension to 2015	Current RPS	$41,599
Case-09a	CO_2 Tax	Low to very high	Medium	Extension to 2015	Current RPS	$41,616
Case-10	CO_2 Tax	Low to very high	Medium	Extension to 2020	Current RPS	$41,277
Case-11	CO_2 Tax	Medium	High	Extension to 2015	Current RPS	$42,092
Case-12	CO_2 Tax	High	High	Extension to 2015	Current RPS	$46,954
Case-13	CO_2 Tax	Low to very high	High	Extension to 2015	Current RPS	$42,705
Case-14	CO_2 Tax	Low to very high	High	Extension to 2020	Current RPS	$41,982
Case-15	Hard Cap - Base	Medium	Low	Extension to 2015	Current RPS	$31,049
Case-16	Hard Cap - Base	Medium	Medium	Extension to 2015	Current RPS	$32,845
Case-17	Hard Cap - Base	Medium	High	Extension to 2015	Current RPS	$34,968
Case-18	Hard Cap - OR	Medium	Medium	Extension to 2015	Current RPS	$34,926
Case-19	$19/ton	Medium	Medium	Extension to 2015	Current RPS	$42,556

Table D.4 – Core Case Portfolios (Case 1 to 14)

Case 1

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	23	12	23	6	35	-	143
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	23	12	23	6	35	-	143
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	17	50	-	23	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	90	95
DSM, Class 2, Goshen	1	1	1	1	1	1	2	2	1	2	1	2	2	3	3	3	3	3	3	2	13	36
DSM, Class 2, Utah	46	55	59	44	64	41	44	44	45	48	51	55	52	55	55	60	56	59	59	62	489	1,053
DSM, Class 2, Wyoming	3	4	4	5	5	5	6	6	6	7	8	9	10	12	13	17	18	21	26	28	51	211
DSM, Class 2 Total	49	59	64	50	70	47	51	52	53	56	61	65	64	69	71	79	76	82	88	92	552	1,300
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	2.37	2.37	-	-	-	-	-	23	28
FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	0	200	-	4	154	-	191	-	-	-	-	-	-	-	-	-	-	115	57
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	8	22	116	103	107	131	123	123	127	140	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	87	182	347	376	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	64	8	130	156	178	202	263	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	4	4	4	5	5	5	5	4	4	3	3	3	44	85
DSM, Class 2, Oregon/California	51	51	54	59	60	59	59	51	51	51	51	51	52	52	52	52	44	36	36	36	547	1,009
DSM, Class 2, Yakima	10	11	6	6	6	6	6	6	6	6	7	7	7	8	8	6	5	6	6	6	68	133
DSM, Class 2 Total	65	66	65	70	71	69	69	61	61	61	62	63	63	64	64	62	53	45	45	45	659	1,226
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	0.97	1.29	0.97	0.97	0.97	-	-	0.97	0.97	0.97	-	-	-	-	-	12	15
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	400	337	400	309	400	400	400	400	400	400	400	400	400	354	372
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	2	50	50	-	50	-	33	50	50	50	50	50	50	50	50	35	39
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	183	140	110	174	204	188	N/A	100
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	N/A	4
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	138	200	284	182	177	210	N/A	119
Annual Additions, Long Term Resources	153	210	199	792	310	740	129	130	597	171	131	133	133	142	223	170	146	160	144	177		
Annual Additions, Short Term Resources	350	1,213	1,419	1,164	1,099	702	754	904	637	941	617	756	866	917	1,185	1,359	1,510	1,626	1,807	1,928		
Total Annual Additions	503	1,422	1,618	1,956	1,409	1,443	883	1,034	1,234	1,112	748	889	999	1,059	1,408	1,529	1,656	1,786	1,951	2,105		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 2

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	2	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	17	48	-	20	-	-	10	-	-	2	-	-	-	-	-	-	-	5	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	46	57	59	43	44	47	52	55	56	74	51	55	53	55	55	60	56	59	63	66	535	1,109
DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	10	12	13	17	18	21	26	28	55	214
DSM, Class 2 Total	49	62	64	48	51	55	60	64	65	84	61	66	65	70	71	79	76	82	92	95	603	1,361
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	-	-	-	-	24	24
FOT Mead 3rd Qtr HLH	-	168	264	264	-	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	37
FOT Utah 3rd Qtr HLH	200	200	200	16	-	-	62	200	-	200	-	-	-	-	-	-	-	-	-	-	108	54
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	70	125	149	148	109	111	125	138	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	109	150	377	344	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	50	116	193	150	273	219	-	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	4	5	5	5	5	4	4	3	3	4	45	87
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	51	51	52	52	52	52	44	36	36	36	550	1,011
DSM, Class 2, Yakima	10	11	6	6	6	6	7	7	7	7	7	7	7	8	8	6	5	6	6	7	73	141
DSM, Class 2 Total	65	66	65	70	71	70	71	63	63	64	63	63	63	64	64	62	53	46	46	46	669	1,239
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	-	16	16
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	315	400	400	400	371	400	320	400	400	400	400	400	400	400	400	400	349	370
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	43	50	50	50	50	50	50	50	50	35	40
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	-	146	107	203	236	N/A	78
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	685	N/A	68
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	53	-	99	199	245	48	203	153	N/A	100
Annual Additions, Long Term Resources	153	210	200	776	817	154	162	146	614	205	131	135	134	139	140	147	134	138	142	147		
Annual Additions, Short Term Resources	350	1,213	1,419	1,180	665	789	812	950	671	950	626	763	872	925	1,225	1,398	1,550	1,666	1,844	1,961		
Total Annual Additions	503	1,423	1,619	1,956	1,482	943	974	1,096	1,285	1,155	757	897	1,006	1,064	1,365	1,545	1,684	1,804	1,986	2,108		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 3

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
		Capacity (MW)																					
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	4	34	-	139
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	4	34	-	139
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	-	-	97	97
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	55	59	43	44	47	50	53	55	64	52	60	57	59	60	65	60	63	64	69	517	1,125
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	10	12	13	17	20	23	29	28	55	221
	DSM, Class 2 Total	49	59	64	48	51	55	58	62	64	74	62	70	69	74	75	84	82	89	95	99	586	1,384
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	24	37
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	57	198	-	200	-	-	-	-	-	-	-	-	-	-	107	54
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	68	90	179	109	196	161	139	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	168	352	353	107	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	334	-	329	336	-	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	4	5	5	5	5	4	4	3	3	4	45	87
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	51	51	52	52	52	52	44	36	36	36	550	1,014
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	7	7	7	8	8	6	5	6	6	7	70	138
	DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	64	63	63	64	65	65	63	53	46	46	46	665	1,239
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	0.97	0.97	-	-	-	-	-	-	16	18
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	370	400	-	69	400	400	400	400	400	400	400	400	347	337
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	52	131	209	-	205	-	203	200	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	279	-	-	721	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	318	369	78	11	142	82	-	-	-	-	N/A	100
	Growth Resource Oregon/California *	151	210	200	776	837	153	150	144	613	202	135	141	142	161	267	173	149	149	150	184		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	774	807	948	670	950	624	758	862	910	1,144	1,314	1,461	1,577	1,752	1,867		
	Total Annual Additions	501	1,422	1,620	1,957	1,486	927	958	1,092	1,283	1,152	759	899	1,004	1,071	1,411	1,487	1,610	1,726	1,902	2,051		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 4

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	12	49	20	8	9	4	34	-	136
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	12	49	20	8	9	4	34	-	136
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	51	-	20	-	-	10	-	-	-	-	-	-	-	-	5	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	41
DSM, Class 2, Utah	47	54	59	43	44	51	52	54	57	60	56	63	61	63	64	68	63	67	68	74	520	1,166
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	14	15	19	20	24	29	28	56	233
DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	74	74	80	82	90	86	94	100	104	590	1,441
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	24	39
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	44	185	-	200	-	-	-	-	-	-	-	-	-	-	105	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	137	97	185	97	167	123	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	242	287	366	-	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	144	177	204	173	302	-	-	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	8	8	9	9	7	6	7	6	7	71	147
DSM, Class 2 Total	63	66	65	70	72	71	71	63	63	64	64	65	66	67	67	64	55	47	47	47	668	1,257
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.48	0.97	0.97	-	-	-	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	357	400	-	-	107	312	400	350	-	-	-	-	345	231
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	3	150	-	43	-	204	200	202	199	N/A	100
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	214	-	221	565	N/A	100
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	313	426	261	-	-	-	151	204	443	202	N/A	200
Annual Additions, Long Term Resources	152	210	200	777	837	156	161	144	614	188	143	149	148	168	276	187	154	155	631	1,388		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	648	771	794	935	657	950	619	748	850	893	1,121	1,282	1,426	1,538	1,290	1,402		
Total Annual Additions	502	1,422	1,620	1,957	1,485	927	955	1,079	1,271	1,138	762	897	998	1,060	1,397	1,468	1,580	1,693	1,920	2,790		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 5

	Capacity (MW)																				Resource Totals **	
Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**10-year**	**20-year**
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	475	475	475	2,375
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	13	139	21	8	9	4	34	-	227
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	13	139	21	8	9	4	34	-	227
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	-	-	97	97
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	41
DSM, Class 2, Utah	46	54	59	43	44	47	52	53	56	61	56	60	57	63	64	68	64	67	68	74	517	1,158
DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	15	19	20	24	29	28	55	232
DSM, Class 2 Total	49	59	64	48	51	55	60	62	66	71	67	71	70	80	82	90	87	94	100	105	586	1,431
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.64	2.64	2.64	2.37	-	-	-	-	-	24	36
FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	56	196	-	200	-	-	-	-	-	-	-	-	-	-	107	54
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	-	-	210	210
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	45	110	161	144	171	173	139	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	346	494	160	-	-	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	224	218	412	132	-	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	90
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	550	1,017
DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	70	145
DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	64	64	65	65	66	67	64	55	47	47	47	666	1,253
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	-	-	-	-	-	-	16	20
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	368	400	314	400	400	284	-	-	-	-	-	-	347	243
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	31	122	269	-	-	74	-	-	-	N/A	50
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	145	151	157	186	170	N/A	120
Annual Additions, Long Term Resources	152	209	200	776	837	153	152	144	614	199	142	145	144	167	330	181	630	630	631	1,985		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	774	806	946	668	950	620	751	855	898	1,158	1,324	1,047	739	491	308		
Total Annual Additions	502	1,422	1,620	1,957	1,486	927	958	1,091	1,282	1,149	762	896	999	1,066	1,488	1,505	1,677	1,369	1,121	2,294		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 6

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
		Capacity (MW)																					
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	475	475	475	2,375
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	40	-	-	-	-	29	21	8	9	4	34	40	145
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	-	-	200	-	-	-	-	29	21	8	9	4	34	200	305
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	16	51	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	96	96
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	41
	DSM, Class 2, Utah	46	53	59	38	44	47	49	50	52	54	56	60	57	63	64	68	64	67	68	74	492	1,134
	DSM, Class 2, Wyoming	3	4	4	4	5	5	6	7	6	7	9	9	11	13	15	19	20	24	29	28	51	228
	DSM, Class 2 Total	49	57	64	43	50	54	56	59	60	63	67	71	70	80	82	90	87	94	100	105	557	1,402
	Micro Solar - Water Heater	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	2.37	2.37	-	-	-	-	-	21	26
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	41	-	12	158	200	-	198	-	-	-	-	-	-	-	-	-	-	121	60
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	-	-	210	210
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	33	46	107	160	150	168	172	139	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	319	464	218	-	-	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38	189	227	414	132	-	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	-	-	-	35	-	35	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	44	89
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	51	52	52	52	52	52	53	52	44	37	37	36	549	1,016
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	6	6	8	8	8	9	9	7	6	7	6	7	67	142
	DSM, Class 2 Total	63	66	65	69	71	70	70	62	61	62	64	65	65	66	67	64	55	47	47	47	660	1,247
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	0.97	-	-	-	-	-	14	15
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	385	400	400	400	339	400	313	400	400	326	-	-	-	-	-	-	352	248
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	32	124	229	-	-	-	-	-	-	N/A	38
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	396	214	154	160	189	173	N/A	129
	Annual Additions, Long Term Resources	155	209	199	751	766	152	136	249	646	365	138	141	141	153	222	181	630	630	631	1,985		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,205	735	861	908	950	639	948	619	752	857	901	1,160	1,326	1,049	741	492	312		
	Total Annual Additions	505	1,421	1,620	1,955	1,501	1,012	1,043	1,199	1,285	1,313	757	893	997	1,054	1,382	1,507	1,679	1,371	1,123	2,297		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 7

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	4	34	-	55
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	8	9	4	34	-	215
CHP - Biomass	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	6	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	6	62	-	20	-	-	8	-	-	-	-	-	-	-	-	-	-	-	5	-	95	100
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	46	55	59	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	499	1,113
DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	55	229
DSM, Class 2 Total	49	59	64	48	51	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	568	1,380
Micro Solar - Water Heater	-	3	3	3	3	3	3	3	3	3	2	2	0	-	-	-	-	-	-	-	24	29
FOT Mead 3rd Qtr HLH	-	168	264	264	-	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	-	200	200	22	-	-	57	200	-	193	-	-	-	-	-	-	-	-	-	-	87	44
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	34	81	184	237	-	238	169	57	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	306	335	358	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	-	261	290	395	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
CHP - Biomass	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	63	138
DSM, Class 2 Total	61	62	65	70	71	70	70	63	63	63	64	65	65	66	66	64	54	47	47	47	658	1,243
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.0	1.0	1.0	1.0	-	-	-	-	-	-	15	19
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	25	400	400	400	303	400	400	400	376	400	96	292	388	400	400	400	400	400	400	400	350	354
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	12	-	-	56	52	167	-	32	165	N/A	48
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	412	-	-	-	N/A	41
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	217	140	126	114	250	316	225	115	264	231	N/A	200
Annual Additions, Long Term Resources	138	217	200	776	837	153	155	140	607	216	142	145	142	148	308	155	150	150	155	185		
Annual Additions, Short Term Resources	175	1,239	1,425	1,186	653	778	807	950	676	943	612	744	848	895	1,190	1,358	1,505	1,621	1,791	1,906		
Total Annual Additions	313	1,456	1,625	1,962	1,490	931	962	1,090	1,283	1,159	754	889	990	1,043	1,498	1,513	1,655	1,770	1,946	2,090		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 8

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
		Capacity (MW)																					
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	50
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	50
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	20	-	-	10	-	-	-	-	-	-	2	-	3	-	-	-	-	94	99
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	42
	DSM, Class 2, Utah	47	57	59	43	46	50	52	54	55	60	59	63	61	63	65	69	64	67	68	77	524	1,181
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	10	11	14	15	19	20	24	29	28	56	234
	DSM, Class 2 Total	51	62	64	49	53	57	61	63	65	69	70	75	74	80	83	91	87	94	100	108	594	1,457
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	-	24	34
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	43	184	-	200	-	-	-	-	-	-	-	-	-	-	104	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	19	32	44	58	195	144	195	171	136	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	205	308	370	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	222	185	365	228	-	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,019
	DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	670	1,260
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	-	-	-	-	-	-	16	20
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	317	400	-	99	400	371	400	400	400	103	-	-	341	279
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	0	47	142	206	-	204	-	201	199	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,000	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	312	328	68	-	121	131	41	334	466	200	N/A	200
	Annual Additions, Long Term Resources	153	210	200	777	839	156	161	144	658	143	146	150	149	193	225	163	150	155	156	916		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	647	770	793	934	617	950	617	746	847	857	1,085	1,247	1,390	1,503	1,674	2,205		
	Total Annual Additions	503	1,423	1,620	1,957	1,486	926	955	1,078	1,275	1,093	764	896	996	1,049	1,311	1,411	1,541	1,658	1,830	3,121		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 9

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	200	200	-	500
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	13	49	21	8	9	200	200	-	500
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	11	14
DSM, Class 1 Total	16	48	-	20	-	-	5	-	-	5	-	-	-	-	-	5	-	-	-	-	94	99
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
DSM, Class 2, Utah	47	57	59	43	44	50	52	54	57	60	56	63	61	63	65	69	64	70	70	77	523	1,183
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	14	15	19	20	24	30	29	56	236
DSM, Class 2 Total	51	62	64	49	51	58	60	63	66	69	67	75	74	80	83	91	88	97	103	109	594	1,461
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	24	37
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	106	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	210	240
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	48	48	69	59	82	97	169	196	227	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	33	114	172	82	164	344	92	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	10	9	20	83	17	287	260	314	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	70	70	70	245
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	37	551	1,019
DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	48	669	1,260
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	1.29	0.97	0.97	0.97	-	-	-	-	-	16	21
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	366	400	313	400	400	400	400	119	-	-	-	-	346	275
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	205	-	-	-	-	N/A	23
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	-	-	-	N/A	45
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	57	-	143	408	392	433	371	196	N/A	200
Annual Additions, Long Term Resources	152	210	200	777	837	156	152	144	614	197	143	150	149	168	278	187	156	158	901	2,227		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	648	771	803	944	666	950	619	748	849	892	1,119	1,279	1,421	1,532	1,218	737		
Total Annual Additions	502	1,423	1,620	1,957	1,485	927	955	1,088	1,280	1,147	762	898	998	1,060	1,397	1,466	1,577	1,690	2,119	2,964		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 9a

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	200	200	-	418
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	200	200	-	418
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	23	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	87	92
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
	DSM, Class 2, Utah	47	57	59	47	62	47	49	50	52	54	56	63	61	63	65	69	64	70	70	77	525	1,184
	DSM, Class 2, Wyoming	3	4	4	5	5	5	6	7	7	8	9	9	11	14	15	19	20	24	30	29	54	234
	DSM, Class 2 Total	51	62	64	53	68	54	56	59	61	64	67	75	74	80	83	91	88	97	103	109	593	1,460
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	-	-	-	-	-	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	11	23
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	0	200	-	-	146	-	179	-	-	-	-	-	-	-	-	-	-	113	56
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	210	240
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	7	20	77	75	59	82	99	151	196	233	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	24	85	143	89	238	332	89	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	36	173	264	252	267	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	35	-	-	70	70	70	280
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	9	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	37	550	1,019
	DSM, Class 2, Yakima	10	11	7	7	7	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	73	150
	DSM, Class 2 Total	65	66	66	71	72	70	70	62	63	63	65	66	66	67	67	64	55	47	47	48	669	1,260
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	-	-	-	-	-	0.97	0.97	0.97	0.97	0.97	-	-	-	-	-	7	12
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	400	328	400	281	396	400	400	400	-	-	-	-	-	353	270
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	245	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	2	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	206	-	-	-	-	N/A	23
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	136	-	-	-	N/A	14
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	16	-	153	502	413	423	318	175	N/A	200
	Annual Additions, Long Term Resources	154	210	200	793	311	744	132	135	604	177	143	150	149	156	229	201	156	158	901	2,227		
	Annual Additions, Short Term Resources	350	1,213	1,419	1,164	1,099	702	750	896	628	929	588	716	817	860	1,087	1,216	1,359	1,469	1,156	675		
	Total Annual Additions	504	1,423	1,619	1,957	1,410	1,446	882	1,031	1,232	1,106	730	866	966	1,016	1,316	1,417	1,515	1,627	2,057	2,901		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 10

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	597	1,222	1,819
CCCT H	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	475	-	950
SCCT Aero Utah	-	-	-	-	-	-	-	-	-	118	-	-	-	-	-	-	-	-	-	-	118	118
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200	200	200	600
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
Total Wind	-	-	-	-	-	-	-	-	160	200	-	-	-	-	-	-	-	-	200	200	360	760
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	2	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	9	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	3	-	-	-	-	11	14
DSM, Class 1 Total	15	49	-	-	-	-	-	-	-	30	-	-	-	-	-	5	-	-	-	-	94	99
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
DSM, Class 2, Utah	47	56	59	43	44	47	49	52	55	59	56	63	61	63	65	69	64	70	70	77	512	1,172
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	14	15	19	20	24	31	29	56	237
DSM, Class 2 Total	51	60	64	49	51	55	57	61	65	69	67	75	74	80	83	91	88	97	104	109	583	1,451
Micro Solar - Water Heater	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	-	-	-	-	26	26
FOT Mead 3rd Qtr HLH	-	168	264	264	-	42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	37
FOT Utah 3rd Qtr HLH	200	200	200	36	-	-	-	76	117	200	-	-	-	-	-	-	-	-	-	-	103	51
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	-	210	240
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	44	32	45	59	98	97	193	214	211	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	7	5	134	69	269	-	329	187	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	342	400	241	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	-	70	70	70	70	70	-	-	-	-	-	-	-	-	70	70	350	490
Utility Biomass	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	37	550	1,019
DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	71	148
DSM, Class 2 Total	63	66	65	70	71	71	70	63	63	64	64	66	66	67	67	64	55	47	47	48	668	1,258
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	-	18	18
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	380	400	400	400	400	400	315	400	400	400	400	-	-	-	-	-	358	275
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	50	46	50	50	50	-	-	-	-	-	-	-	-	-	-	40	20
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	105	-	159	205	-	-	-	-	N/A	47
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	757	-	-	-	N/A	76
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	11	19	200	459	336	436	186	353	N/A	200
Annual Additions, Long Term Resources	156	210	200	757	767	223	242	212	413	620	139	146	146	152	155	166	148	149	902	2,227		
Annual Additions, Short Term Resources	350	1,213	1,420	1,200	730	792	746	826	867	950	621	751	853	898	1,188	1,348	1,490	1,601	1,287	805		
Total Annual Additions	506	1,422	1,620	1,957	1,497	1,016	988	1,038	1,280	1,570	760	897	999	1,050	1,343	1,513	1,638	1,749	2,189	3,032		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 11

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	0.0	0.8	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	10	-	-	-	-	-	-	5	-	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	44
	DSM, Class 2, Utah	47	57	59	47	58	52	54	71	72	74	61	65	62	67	68	72	66	70	70	77	591	1,269
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	8	8	8	9	10	11	14	15	19	20	24	31	29	57	240
	DSM, Class 2 Total	51	62	64	53	65	60	62	80	81	85	72	77	76	84	86	94	90	97	104	109	664	1,553
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	24	37
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	50	72	77	132	139	96	149	145	135	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	170	-	246	259	325	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	174	-	178	254	326	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	35	70	70	70	70	-	-	-	-	-	-	-	35	-	-	385	420
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
	DSM, Class 2, Oregon/California	51	51	54	59	61	60	59	52	52	52	52	52	52	53	53	52	44	37	37	37	552	1,021
	DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	75	152
	DSM, Class 2 Total	65	66	66	71	72	71	71	64	64	64	65	66	66	67	67	64	55	47	47	48	674	1,266
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	-	-	-	-	-	16	24
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	311	342	400	400	400	81	393	400	400	400	400	400	400	400	365	345	355
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	50	-	6	34	50	-	-	-	-	-	-	-	-	-	-	34	17
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	174	-	-	-	N/A	20
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	292	-	-	-	N/A	29
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	229	-	70	104	268	124	205	273	356	371	N/A	200
	Growth Resource Oregon/California *	155	310	201	790	310	791	213	232	269	275	149	153	152	160	162	164	155	184	157	162		
	Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	661	642	706	734	950	616	743	842	881	1,168	1,330	1,467	1,546	1,714	1,822		
	Total Annual Additions	505	1,523	1,616	1,954	1,409	1,452	854	938	1,003	1,225	765	895	994	1,042	1,330	1,494	1,621	1,730	1,871	1,983		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 12

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	-	1,800
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
Total Wind	-	-	-	-	-	-	-	-	160	-	-	200	200	200	200	200	200	200	200	200	160	1,960
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	1	-	-	2	-	-	-	-	11	14
DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	7	-	-	2	-	-	3	-	-	-	-	94	99
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	45
DSM, Class 2, Utah	47	57	59	47	54	52	54	55	57	73	62	67	64	68	68	72	66	70	70	77	554	1,240
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	8	8	9	10	11	14	15	20	21	25	31	29	57	242
DSM, Class 2 Total	51	62	64	53	61	60	62	65	67	83	74	79	78	85	87	95	91	98	104	109	627	1,527
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	24	42
FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	59	79	88	63	120	125	95	115	121	134	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	3	-	184	304	459	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	91	21	59	-	-	115	-	190	202	321	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	70	70	70	70	70	-	-	-	-	-	-	-	-	-	-	420	420
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	59	52	52	52	52	52	52	53	53	53	45	37	37	37	552	1,023
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	7	8	9	9	9	10	7	6	7	7	7	75	154
DSM, Class 2 Total	65	66	66	71	72	71	71	63	64	64	65	66	66	68	68	65	55	48	47	48	674	1,269
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	0.97	-	-	16	29
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	313	311	388	397	400	134	339	387	400	400	400	400	400	400	-	341	333
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	17	-	-	-	50	-	-	-	-	-	-	-	-	-	-	27	13
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	111	189	59	187	184	N/A	73
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	286	-	-	271	N/A	56
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	30	-	-	110	288	262	185	316	218	592	N/A	200
Annual Additions, Long Term Resources	155	310	201	790	405	825	213	216	450	234	151	355	356	362	365	372	355	351	357	1,085		
Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	630	611	688	697	950	614	739	834	873	1,158	1,316	1,455	1,564	1,732	2,261		
Total Annual Additions	505	1,523	1,616	1,954	1,504	1,456	823	904	1,147	1,184	765	1,094	1,191	1,235	1,523	1,688	1,809	1,915	2,089	3,346		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 13

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	1,600
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	-	1,600
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	-	1,600
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	0.8	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	10	-	-	-	2	-	3	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	45
DSM, Class 2, Utah	47	57	59	47	58	52	54	71	72	74	61	67	64	68	68	72	66	70	70	73	591	1,271
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	8	8	8	9	10	11	14	15	20	21	25	31	33	57	246
DSM, Class 2 Total	51	62	64	53	65	60	62	80	81	85	72	79	78	85	87	95	91	98	104	109	664	1,562
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	24	45
FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	41	67	78	120	125	118	160	152	134	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	162	19	342	396	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	71	97	70	149	211	193	210	-	N/A	100
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	35	70	70	70	70	-	-	-	-	-	35	-	-	-	-	385	420
Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	59	52	52	52	52	52	52	53	53	53	45	37	37	37	552	1,022
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	8	8	9	9	9	10	7	6	7	7	7	75	154
DSM, Class 2 Total	65	66	66	71	72	71	71	64	64	64	65	66	66	67	68	65	55	48	47	48	674	1,270
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	1.29	0.97	0.97	-	16	30
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	341	342	400	400	400	310	400	400	400	400	400	400	102	-	-	348	315
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	20	-	6	34	50	-	-	-	-	-	-	-	-	-	-	31	16
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	137	-	40	-	N/A	18
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	190	150	240	437	603	380	N/A	200
Annual Additions, Long Term Resources	155	310	201	790	310	790	213	232	269	275	149	155	354	364	365	407	355	354	358	2,685		
Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	661	642	706	734	950	616	741	838	875	1,160	1,287	1,425	1,533	1,701	814		
Total Annual Additions	505	1,523	1,616	1,954	1,409	1,452	854	938	1,003	1,225	765	896	1,192	1,239	1,525	1,693	1,780	1,887	2,059	3,499		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 14

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
	Capacity (MW)																					
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
CCCT H	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	-	475	475
SCCT Aero Utah	-	-	-	-	-	118	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118	118
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	1,600
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	200	200	200	-	-	-	200	200	200	200	200	200	200	600	2,000
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	160
Total Wind	-	-	-	-	-	-	-	200	200	200	-	160	-	200	200	200	200	200	200	200	600	2,160
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	8	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	11	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1 Total	16	48	-	-	20	-	12	-	-	-	-	-	-	2	-	3	-	-	-	-	96	101
DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	16	45
DSM, Class 2, Utah	47	57	60	47	68	71	71	62	72	74	61	67	64	67	68	72	66	70	70	73	628	1,308
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	8	8	9	10	11	14	15	20	21	25	31	33	57	246
DSM, Class 2 Total	51	62	65	53	75	79	79	71	81	85	72	79	78	84	87	95	91	98	104	109	701	1,599
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	24	45
FOT Mead 3rd Qtr HLH	-	168	264	264	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89	45
FOT Utah 3rd Qtr HLH	200	200	200	32	200	188	200	-	-	200	-	-	-	-	-	-	-	-	-	-	142	71
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	85	98	120	126	111	147	155	134	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	136	172	316	323	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	21	53	77	138	126	48	177	164	-	N/A	80
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	70	70	-	70	70	-	-	-	-	-	58	-	-	-	-	350	408
Wind, Yakima, 29% Capacity Factor	-	-	-	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Total Wind	-	-	-	-	100	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	4	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	49	-	4	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	93
DSM, Class 2, Oregon/California	51	51	54	59	61	60	60	52	52	52	52	52	52	53	53	53	45	37	37	37	552	1,022
DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	7	8	9	9	9	10	7	6	7	7	7	75	154
DSM, Class 2 Total	65	66	66	71	72	71	71	63	64	64	65	66	66	67	68	65	55	48	47	48	674	1,269
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	0.97	0.97	-	16	29
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	364	391	400	310	400	400	400	400	400	400	-	-	-	355	313
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	203	-	173	-	N/A	38
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149	179	171	574	567	360	N/A	200
Annual Additions, Long Term Resources	155	210	201	762	440	367	384	827	469	428	149	315	154	364	365	430	355	354	358	2,685		
Annual Additions, Short Term Resources	350	1,213	1,419	1,196	1,099	1,037	950	664	691	950	616	741	838	875	1,160	1,266	1,405	1,513	1,681	794		
Total Annual Additions	505	1,423	1,619	1,957	1,539	1,404	1,334	1,491	1,161	1,378	765	1,056	992	1,239	1,525	1,696	1,760	1,867	2,039	3,479		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.5 – Hard Cap CO2 Policy Core Case (15 to 18)

Case 15

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	-	-	475	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	14	49	21	8	9	4	34	-	139
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	14	49	21	8	9	4	34	-	139
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	-	-	97	97
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	40
	DSM, Class 2, Utah	46	55	59	43	44	47	50	53	56	60	56	60	57	60	60	65	63	66	67	69	515	1,136
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	11	13	14	18	20	23	29	28	54	228
	DSM, Class 2 Total	49	59	64	48	50	55	58	62	66	70	66	71	70	76	77	86	85	92	99	99	583	1,404
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	24	37
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	38
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	53	193	-	200	-	-	-	-	-	-	-	-	-	-	106	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	45	59	180	202	155	161	139	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58	384	16	-	-	-	N/A	46
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	243	307	57	196	197	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	89
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	37	37	36	550	1,016
	DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	8	8	9	9	7	6	6	6	7	71	145
	DSM, Class 2 Total	63	66	65	70	71	70	71	63	63	64	64	65	65	66	66	64	54	47	47	47	667	1,251
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	-	-	-	-	-	-	-	-	-	-	16	16
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	364	400	193	400	400	400	400	147	153	159	187	400	346	315
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	-	50	50	-	50	-	-	-	50	50	50	50	50	50	50	30	33
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	122	33	124	108	268	-	-	-	-	345	N/A	100
	Annual Additions, Long Term Resources	152	210	200	776	836	154	154	145	615	195	140	144	143	164	270	177	628	628	154	907		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	773	803	943	664	950	621	753	857	903	1,135	1,303	1,028	722	894	1,431		
	Total Annual Additions	502	1,422	1,620	1,957	1,486	927	957	1,087	1,278	1,145	761	897	1,000	1,067	1,405	1,480	1,656	1,349	1,048	2,338		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 16

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	475	475	475	-	475	1,900
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	9	4	34	-	50
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	11	14
DSM, Class 1 Total	26	37	-	20	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	5	87	92
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
DSM, Class 2, Utah	47	57	59	43	44	47	51	52	54	57	59	63	62	65	65	69	64	67	68	74	513	1,170
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	10	11	14	15	19	20	24	29	28	56	233
DSM, Class 2 Total	51	62	64	49	51	55	59	62	63	67	71	75	76	82	83	91	87	94	100	104	583	1,446
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	-	-	24	34
FOT Mead 3rd Qtr HLH	-	168	264	264	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	38
FOT Utah 3rd Qtr HLH	189	200	200	17	-	-	58	200	-	188	-	-	-	-	-	-	-	-	-	-	105	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	122	300	210	246
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	32	116	110	223	99	133	125	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	96	-	-	-	-	N/A	10
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	107	256	453	114	41	-	-	N/A	97
West																						
CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	56	56
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	669	1,259
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	-	-	-	-	-	-	-	16	19
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	334	400	-	305	163	9	389	148	400	160	188	400	343	280
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	-	-	50	50	-	50	50	50	50	50	50	50	50	50	-	48	30	37
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	250	60	289	294	-	-	29	-	-	79	N/A	100
Annual Additions, Long Term Resources	163	200	200	777	837	153	149	143	656	175	147	150	151	156	225	161	626	630	631	918		
Annual Additions, Short Term Resources	339	1,213	1,420	1,181	648	773	808	950	634	938	606	734	834	876	1,104	1,269	992	684	436	964		
Total Annual Additions	503	1,412	1,620	1,957	1,485	926	957	1,093	1,290	1,114	752	884	985	1,032	1,330	1,430	1,618	1,315	1,066	1,882		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 17

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
		Capacity (MW)																					
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	35	35
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,600	-	1,600
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	40	200	200	200	200	200	200	200	200	200	200	200	-	440	2,240
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200	-	600	2,400
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	2	1	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	10	22	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	16	48	-	22	1	-	-	-	-	7	2	-	-	-	-	3	-	-	-	-	94	99
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	16	46
	DSM, Class 2, Utah	47	57	60	47	54	52	58	71	72	74	63	67	64	68	68	72	66	70	70	77	593	1,279
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	8	8	8	9	10	12	14	15	20	21	25	31	29	58	243
	DSM, Class 2 Total	51	62	66	53	60	60	67	80	81	85	74	80	79	85	87	95	91	98	104	109	666	1,568
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	24	45
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	200	200	200	-	200	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	100	50
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	4	18	37	67	128	159	95	189	170	134	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82	38	94	344	441	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	327	-	334	339	-	N/A	100
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	35	70	70	70	70	35	-	-	-	-	-	-	-	-	-	385	420
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Walla Walla, 29% Capacity Factor	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	6	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	6	5	4	4	4	4	47	94
	DSM, Class 2, Oregon/California	51	51	54	59	61	60	60	52	52	52	52	52	53	53	53	53	45	37	37	37	552	1,024
	DSM, Class 2, Yakima	10	11	7	7	7	7	7	7	7	8	8	9	9	9	10	7	6	7	7	7	76	156
	DSM, Class 2 Total	65	66	66	71	72	71	71	64	64	64	66	67	67	68	68	65	55	48	47	48	675	1,274
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	-	16	31
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	361	338	400	398	400	-	59	400	400	400	400	400	312	396	376	350	332
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	201	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	-	-	2	-	50	50	50	50	50	50	50	50	50	50	-	25	35
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	-	-	-	N/A	20
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	226	278	14	23	164	8	286	-	-	-	N/A	100
	Annual Additions, Long Term Resources	154	311	201	790	405	791	218	432	505	436	389	356	356	363	365	372	356	354	358	2,485		
	Annual Additions, Short Term Resources	350	1,213	1,415	1,164	1,099	661	638	702	698	950	580	705	801	840	1,125	1,282	1,421	1,529	1,696	810		
	Total Annual Additions	504	1,523	1,616	1,954	1,504	1,452	855	1,134	1,203	1,386	970	1,061	1,157	1,202	1,490	1,655	1,776	1,883	2,054	3,294		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 18

	Resource	Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCS Hunter - Unit 3 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	280	-	280
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	475	475	-	475	475	-	-	475	2,375
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	42	28	21	8	9	200	-	-	308
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	42	28	21	8	9	200	-	-	308
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1 Total	26	37	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	83	86
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	43
	DSM, Class 2, Utah	47	57	59	43	46	50	51	52	54	58	61	65	62	65	66	70	64	68	70	74	518	1,183
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	10	11	14	15	19	20	24	30	28	56	237
	DSM, Class 2 Total	51	62	64	49	53	57	60	62	64	68	72	77	76	82	84	92	88	95	103	105	589	1,463
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	24	34
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71	36
	FOT Utah 3rd Qtr HLH	189	200	200	13	-	-	55	196	-	184	-	-	-	-	-	-	-	-	-	-	104	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	272	120	249	-	-	-	260	210	195
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	168	171	44	58	83	98	111	124	135	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	59	152	-	-	-	-	-	-	-	N/A	21
West																							
	CCS Bridger - Unit 1 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	227
	CCS Bridger - Unit 2 (Replaces Original Unit)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	216	-	216
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	70	105
	Wind, Yakima, 29% Capacity Factor	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	56	56
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	53	53	52	44	37	37	36	551	1,019
	DSM, Class 2, Yakima	8	11	6	6	7	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	670	1,261
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	-	-	-	-	-	-	-	16	20
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	243	400	400	400	280	400	-	-	-	-	-	-	150	156	145	169	332	197
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	203	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	50	50	50	50	50	50	50	50	-	-	5	-	-	-	-	45	30
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	244	150	153	132	139	144	-	-	39	-	N/A	100
	Annual Additions, Long Term Resources	163	300	200	777	840	156	146	143	656	176	149	152	151	673	659	183	631	631	390	882		
	Annual Additions, Short Term Resources	339	1,213	1,417	1,177	643	766	805	946	630	934	599	727	826	448	317	482	248	267	309	564		
	Total Annual Additions	503	1,512	1,617	1,954	1,483	922	951	1,089	1,287	1,110	748	878	977	1,121	977	664	879	898	699	1,446		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.6 – 2011 Business 10-year Plan Case Study 19

Case 19

	Resource	Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	597	-	-	-	-	-	-	-	-	-	-	-	1,819	1,819
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	-	-	-	-	-	-	-	-	80	-	-	-	-	-	-	-	-	80
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	200	300	200	200	200	-	-	-	-	-	-	-	500	1,100
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	-	360	300	200	200	200	-	-	-	-	-	-	-	660	1,260
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	-	10
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	37	-	-	26	-	7	-	-	-	-	-	-	-	-	-	-	5	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	15	39
	DSM, Class 2, Utah	58	65	70	98	104	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	648	1,261
	DSM, Class 2, Wyoming	3	4	4	6	6	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	58	232
	DSM, Class 2 Total	61	70	75	105	112	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	720	1,532
	FOT Mead 3rd Qtr HLH	-	168	264	255	99	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	40
	FOT Utah 3rd Qtr HLH	183	196	200	-	200	-	50	200	-	168	-	-	-	-	-	-	-	-	-	-	120	60
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	7	21	33	46	60	194	123	253	125	138	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	353	338	309	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31	339	171	194	264	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	-	-	-	-	-	-	-	-	-	-	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	-	42
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	43	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	5	6	7	7	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	51	95
	DSM, Class 2, Oregon/California	51	51	55	59	61	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	10	11	9	12	12	6	6	7	7	7	8	8	8	9	9	7	6	6	6	7	87	161
	DSM, Class 2 Total	65	67	70	78	80	71	70	63	63	63	64	65	65	66	66	64	54	46	47	47	689	1,272
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	400	400	400	400	274	400	282	400	400	400	400	400	400	400	400	400	347	368
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT South Central Oregon/Northern California 3rd Qtr HI	-	50	50	50	50	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	40	20
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	19	-	-	-	40	N/A	7
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	1	22	57	330	317	241	31	323	340	N/A	166
	Annual Additions, Long Term Resources	169	197	198	811	238	741	134	130	1,080	427	338	341	421	147	148	155	142	145	147	151		
	Annual Additions, Short Term Resources	333	1,209	1,419	1,155	1,099	755	800	950	574	918	589	721	755	803	1,097	1,261	1,403	1,510	1,680	1,790		
	Total Annual Additions	502	1,406	1,617	1,967	1,337	1,495	935	1,080	1,654	1,344	927	1,063	1,176	949	1,246	1,416	1,545	1,655	1,827	1,941		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.7 – Portfolio Development Assumptions and System Optimizer PVRR Results for Sensitivity Cases (20 to 33)

Case #	Assumption Alternatives										PaR Model	PVRR
	Carbon Policy		Gas Price	Load Growth	Renewable PTC and Wind Integration Cost	Renewable Portfolio Standards	Demand-Side Management	Distributed Solar	Coal Plant Utilization	Energy Gateway Trans		
	Type CO2 Tax Hard Cap	Cost Medium High Low to Very High	Low Medium High	Low Econ. Growth Medium Econ. Growth High Growth High Peak Demand	Extension to 2015 Extension to 2020 Alt. Wind Integ. Cost	None Current RPS Federal RPS	High Achievable Class 3 Included Technical Potential Distribution Efficiency	Current Incentives UT Buydown Levels	No shutdowns Optimized	Base Scenario 1 Scenario 2 Scenario 3		$ Millions
Coal Plant Utilization Sensitivity Cases												
20	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario	X	**$41,123**
21	CO2 Tax	Medium	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario	X	**$39,702**
22	CO2 Tax	High	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario	X	**$46,207**
23	CO2 Tax	High	Low	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario	X	**$44,494**
24	Hard Cap - Base	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	Optimized	Base or Scenario	X	**$32,929**
Load Forecast Sensitivity Cases												
25	CO2 Tax	Medium	Medium	Low Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario	X	**$38,810**
26	CO2 Tax	Medium	Medium	High Econ. Growth	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario	X	**$42,674**
27	CO2 Tax	Medium	Medium	High Peak Demand	Extension to 2015	Current RPS	High Achievable	Current Incentives	None	Base or Scenario		**$41,443**
Renewable Resource Sensitivity Cases												
28	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	None	High Achievable	Current Incentives	None	Base or Scenario		**$40,995**
29	CO2 Tax	Medium	Medium	Med. Econ. Growth	Alt. Wind Integ. Cost	Current RPS	High Achievable	Current Incentives	None	Base or Scenario		**$41,020**
30	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $1.50/Watt Incentive	None	Base or Scenario		**$41,038**
30a	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	High Achievable	UT $2.00/Watt Incentive	None	Base or Scenario		**$41,041**
DSM Sensitivity Cases												
31	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Class 3 Included	Current Incentives	None	Base or Scenario		**$40,536**
32	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Technical Potential	Current Incentives	None	Base or Scenario		**$40,521**
33	CO2 Tax	Medium	Medium	Med. Econ. Growth	Extension to 2015	Current RPS	Distribution Energy	Current Incentives	None	Base or Scenario		**$40,772**

Table D.8 – Coal Plant Utilization Sensitivity Cases (20 to 24)

Case 20

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	11	49	20	8	9	4	34	-	134
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	11	49	20	8	9	4	34	-	134
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	1	-	-	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	1	-	-	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	2	-	-	-	3	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	39
DSM, Class 2, Utah	47	54	59	43	44	51	52	53	56	60	56	60	57	60	60	65	60	63	66	72	519	1,138
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	71	70	76	77	86	82	89	97	102	589	1,406
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	-	-	-	-	24	39
FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	190	200	200	17	-	-	50	190	-	200	-	-	-	-	-	-	-	-	-	-	105	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	19	115	136	65	143	97	158	124	137	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51	-	290	302	357	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	116	-	328	316	230	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	37	36	551	1,016
DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	146
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,254
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	-	-	-	-	16	25
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	362	400	372	400	400	400	400	400	400	400	400	400	346	372
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	50	50	50	50	50	50	50	50	50	35	40
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	39	-	-	208	205	-	148	201	199	N/A	100
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	606	-	-	131	N/A	74
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	46	60	165	179	138	34	188	190	N/A	100
Annual Additions, Long Term Resources	162	200	200	777	837	157	156	144	614	193	143	148	145	162	271	181	150	150	153	188		
Annual Additions, Short Term Resources	340	1,213	1,420	1,181	648	770	800	940	662	950	679	807	911	956	1,188	1,445	1,592	1,707	1,881	1,994		
Total Annual Additions	502	1,412	1,620	1,957	1,485	927	955	1,084	1,276	1,143	822	956	1,056	1,119	1,458	1,626	1,741	1,857	2,034	2,182		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 21

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	289
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	3	34	-	48
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	3	34	-	48
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	11	20	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	17	50	-	20	-	-	5	-	-	5	2	-	-	-	-	3	-	-	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	55	59	43	44	47	50	53	55	64	56	60	57	60	60	65	60	63	64	69	517	1,130
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	8	9	10	13	14	18	20	23	29	28	55	226
	DSM, Class 2 Total	49	59	64	48	51	55	58	62	64	74	66	70	69	76	77	86	82	89	95	99	586	1,394
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	-	-	-	-	24	34
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	57	198	-	200	-	-	-	-	-	-	-	-	-	-	107	54
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	32	44	118	182	118	173	173	137	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	66	374	327	164	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	270	-	323	407	-	N/A	100
West																							
	Coal Utilization - Bridger with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	389
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	0.3	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	4	4	3	4	4	45	88
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	7	7	7	8	9	7	6	6	6	7	70	140
	DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	64	63	64	64	65	66	63	54	46	46	47	665	1,243
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.70	1.81	1.81	1.81	-	-	-	-	-	-	16	23
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	370	400	400	400	400	400	400	400	400	400	400	400	347	373
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	35	43
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	153	141	71	-	204	29	202	200	N/A	100
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	-	-	706	N/A	100
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	15	134	73	119	316	151	135	35	-	22	N/A	100
	Annual Additions, Long Term Resources	151	210	200	776	837	153	150	144	613	202	143	144	143	161	253	157	141	140	150	862		
	Annual Additions, Short Term Resources	350	1,213	1,420	1,181	649	774	807	948	670	950	771	903	1,007	1,054	1,255	1,421	1,568	1,684	1,859	1,979		
	Total Annual Additions	501	1,422	1,620	1,957	1,486	927	958	1,092	1,283	1,152	913	1,047	1,150	1,215	1,508	1,579	1,709	1,824	2,009	2,841		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 22

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	289
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	475	475	950
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	4	34	-	46
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	4	34	-	46
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	7	-	3	26	36
DSM, Class 1, Utah-DLC-Residential	10	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	1	-	-	-	-	2	-	-	-	-	11	14
DSM, Class 1 Total	16	48	-	20	-	-	10	-	-	-	2	-	-	-	-	3	-	7	-	3	94	108
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	42
DSM, Class 2, Utah	47	57	59	43	46	50	52	54	55	60	59	63	62	65	65	69	64	69	70	77	524	1,188
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	10	11	14	15	19	20	24	30	28	56	235
DSM, Class 2 Total	51	62	64	49	53	57	61	63	65	69	71	75	76	82	83	91	87	96	103	108	594	1,465
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	24	39
FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	43	184	-	200	-	-	-	-	-	-	-	-	-	-	104	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	105	53	121	147	97	157	161	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	148	339	456	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	4	-	42	218	34	360	344	-	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,019
DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	670	1,260
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.42	0.97	0.97	0.97	-	-	-	-	-	16	22
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	317	400	400	400	400	400	400	400	400	400	400	400	341	371
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	62	118	104	-	28	-	-	-	N/A	31
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	353	-	-	647	N/A	100
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	12	127	74	84	217	223	128	35	101	-	N/A	100
Annual Additions, Long Term Resources	153	210	200	777	839	156	161	144	658	143	150	151	151	192	229	166	147	164	159	960		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	647	770	793	934	617	950	767	895	995	1,006	1,233	1,394	1,537	1,641	1,811	1,533		
Total Annual Additions	503	1,423	1,620	1,957	1,486	926	955	1,078	1,275	1,093	916	1,046	1,146	1,198	1,462	1,560	1,684	1,805	1,969	2,493		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 23

Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
	Capacity (MW)																					
East																						
Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	-	-	-	289	-	578
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	1	-	-	-	-	1	-	-	-	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	11	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	1	-	-	-	2	-	-	-	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	16	51	-	20	-	-	10	-	-	-	1	1	-	-	-	3	-	-	-	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	41
DSM, Class 2, Utah	47	54	59	43	44	51	52	54	57	60	56	63	61	63	64	69	64	67	68	74	520	1,169
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	14	15	19	20	24	29	28	56	233
DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	75	74	80	82	91	87	94	100	104	590	1,444
Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	24	36
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	200	200	200	17	-	-	44	185	-	200	-	-	-	-	-	-	-	-	-	-	105	52
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	5	19	100	98	151	118	115	134	123	136	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	134	353	446	57	-	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	27	35	130	76	283	302	148	-	N/A	100
West																						
Coal Utilization - Bridger with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	-	778
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	8	8	9	9	7	6	7	6	7	71	147
DSM, Class 2 Total	63	66	65	70	72	71	71	63	63	64	64	65	66	67	67	64	55	47	47	47	668	1,257
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	-	-	-	-	-	-	-	-	16	18
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	357	400	400	400	400	400	400	400	400	400	400	400	345	373
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	50	50	50	50	50	50	50	50	50	50	35	43
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	259	119	N/A	38
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	16	130	123	130	237	298	18	-	47	-	N/A	100
Annual Additions, Long Term Resources	152	210	200	777	837	156	161	144	614	188	143	151	148	189	515	941	150	155	631	954		
Annual Additions, Short Term Resources	350	1,213	1,420	1,181	648	771	794	935	657	950	771	899	1,000	1,013	1,278	1,377	1,520	1,632	1,384	1,005		
Total Annual Additions	502	1,422	1,620	1,957	1,485	927	955	1,079	1,271	1,138	914	1,049	1,148	1,202	1,793	2,318	1,670	1,787	2,014	1,959		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 24

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	Coal Utilization - Utah Coal replaced with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	289	-	-	-	-	-	289
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	475	475	475	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	9	4	34	-	49
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	1	-	-	2	-	-	-	-	11	14
	DSM, Class 1 Total	26	37	-	20	-	-	5	-	-	-	-	-	2	-	-	3	-	-	-	-	88	93
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	42
	DSM, Class 2, Utah	47	57	59	43	44	47	51	52	54	57	59	63	61	65	65	69	64	67	68	77	513	1,171
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	10	11	14	15	19	20	24	29	28	56	234
	DSM, Class 2 Total	51	62	64	49	51	55	59	61	63	67	71	75	74	82	83	91	87	94	100	108	583	1,447
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	24	36
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	38
	FOT Utah 3rd Qtr HLH	189	200	200	17	-	-	57	199	-	187	-	-	-	-	-	-	-	-	-	-	105	52
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	41	122	151	178	97	126	123	136	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	66	184	-	579	170	-	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	146	239	256	-	189	169	-	N/A	100
West																							
	Coal Utilization - Bridger with CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	778
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	70	140
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	56	56
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	551	1,018
	DSM, Class 2, Yakima	8	11	6	6	6	6	7	7	7	7	8	9	9	9	9	7	6	7	6	7	72	149
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	65	66	66	67	67	64	55	47	47	47	668	1,259
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	-	-	-	-	-	-	-	16	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	333	400	400	400	400	400	400	400	400	400	400	400	343	372
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	-	50	50	-	50	50	50	50	50	50	50	50	50	50	50	30	40
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	408	-	33	70	N/A	51
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	0	115	192	8	46	84	277	-	149	127	N/A	100
	Annual Additions, Long Term Resources	163	200	200	777	837	153	150	142	656	175	147	150	152	156	228	452	927	155	631	668		
	Annual Additions, Short Term Resources	339	1,213	1,420	1,181	648	773	807	949	633	937	756	885	984	1,026	1,253	1,452	1,532	1,644	1,395	1,084		
	Total Annual Additions	503	1,412	1,620	1,957	1,485	926	957	1,091	1,289	1,112	903	1,035	1,135	1,182	1,481	1,904	2,459	1,799	2,026	1,752		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.9 – Load Forecast Sensitivity Cases (25 to 27)

Case 25

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	-	625	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	-	20
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	20	-	180
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	-	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	6	58	-	26	-	7	-	-	-	-	-	-	-	-	-	-	-	-	5	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	39
DSM, Class 2, Utah	47	63	62	65	49	52	59	53	56	64	56	60	57	60	60	65	60	63	64	69	571	1,184
DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	231
DSM, Class 2 Total	51	68	67	71	55	59	67	63	66	74	67	71	70	76	77	86	82	89	95	99	642	1,453
Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
FOT Mead 3rd Qtr HLH	-	168	264	264	4	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
FOT Utah 3rd Qtr HLH	-	195	199	200	-	68	200	-	-	200	-	-	-	-	-	-	-	-	-	-	106	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	83	120	201	201	-	213	150	31	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	322	273	364	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43	-	232	343	381	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	-	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	43	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
DSM, Class 2, Yakima	6	6	7	7	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	67	141
DSM, Class 2 Total	62	62	66	71	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	665	1,249
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	-	-	-	-	-	-	-	-	-	-	16	16
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	23	400	400	400	400	400	400	258	396	400	-	249	342	359	400	400	400	400	400	400	348	341
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	50	-	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	58	-	-	40	86	173	-	17	158	N/A	53
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	408	-	-	-	N/A	41
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	319	140	123	113	237	270	200	119	262	217	N/A	200
Annual Additions, Long Term Resources	140	223	197	199	870	166	149	741	139	227	138	142	141	147	308	155	142	141	152	171		
Annual Additions, Short Term Resources	173	1,234	1,423	1,364	804	917	950	558	696	950	619	747	848	892	1,179	1,342	1,481	1,586	1,745	1,851		
Total Annual Additions	314	1,456	1,620	1,563	1,674	1,083	1,099	1,299	835	1,177	758	889	989	1,038	1,487	1,497	1,623	1,727	1,897	2,022		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 26

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	1,819	1,819
	SCCT Aero Utah	-	-	-	-	-	-	-	-	-	118	-	-	-	-	-	-	-	-	-	-	118	118
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	-	52
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	52	-	212
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	0.8	-	-	-	-	-	0.8	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	62	-	23	-	-	-	-	7	-	-	-	-	-	-	-	-	-	5	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	39
	DSM, Class 2, Utah	46	55	59	54	47	51	52	55	71	74	56	60	57	60	60	65	60	63	64	72	563	1,179
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	49	59	64	60	53	58	60	64	81	84	67	71	70	76	77	86	82	89	95	102	633	1,447
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	2.4	2.4	2.4	-	-	-	-	-	24	36
	FOT Mead 3rd Qtr HLH	-	168	264	264	45	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	42
	FOT Utah 3rd Qtr HLH	-	200	200	200	-	119	-	-	8	200	-	-	-	-	-	-	-	-	-	-	93	46
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	45	35	155	186	120	146	-	198	103	12	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	318	300	382	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	-	241	263	391	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	6	6	7	7	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	67	141
	DSM, Class 2 Total	61	62	66	71	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	664	1,248
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	1.0	1.0	1.0	-	-	-	-	-	16	21
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	25	400	400	400	400	400	208	360	400	400	14	255	280	318	400	400	400	400	400	400	339	333
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	50	-	-	50	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	38	28	-	-	185	160	173	-	178	174	N/A	94
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	393	-	-	-	N/A	39
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	227	142	133	113	201	260	249	171	254	250	N/A	200
	Annual Additions, Long Term Resources	138	217	200	803	890	157	738	145	206	311	142	145	144	150	312	155	142	141	152	206		
	Annual Additions, Short Term Resources	175	1,239	1,424	1,364	845	968	508	660	758	950	624	761	869	917	1,207	1,371	1,514	1,628	1,797	1,908		
	Total Annual Additions	313	1,456	1,625	2,167	1,735	1,125	1,246	805	963	1,261	766	906	1,013	1,067	1,518	1,526	1,656	1,769	1,948	2,114		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 27

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	597	-	-	-	-	-	-	-	-	-	-	-	-	1,819	1,819
	SCCT Aero Utah	-	-	-	236	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	236	236
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	9
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	9	-	169
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	0.8	0.8	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	58	-	23	-	2	-	-	-	9	-	-	-	-	-	-	-	5	-	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	39
	DSM, Class 2, Utah	46	59	59	46	49	52	53	61	71	74	56	60	57	60	60	65	60	63	64	69	569	1,183
	DSM, Class 2, Wyoming	3	4	4	5	5	6	7	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	49	63	64	52	55	59	62	70	81	84	67	71	70	76	77	86	82	89	95	99	640	1,452
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	-	200	200	177	-	50	200	-	-	200	-	-	-	-	-	-	-	-	-	-	103	51
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	57	119	96	213	-	255	135	125	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	310	356	334	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	-	275	293	380	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	1	-	-	-	2	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	6	-	1	-	-	-	2	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	47	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	6	6	6	7	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	66	140
	DSM, Class 2 Total	61	62	66	71	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	664	1,248
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	-	-	-	-	-	-	-	-	16	18
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	25	400	400	400	400	400	400	266	400	400	198	342	400	400	400	400	400	400	400	400	349	362
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	22	50	50	-	0	50	-	-	-	-	-	-	-	-	-	-	32	16
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	208	161	203	-	146	170	N/A	89
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	418	-	-	-	N/A	42
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	131	128	127	119	241	296	256	156	252	293	N/A	200
	Annual Additions, Long Term Resources	138	218	200	1,025	892	162	143	750	155	250	139	143	141	147	308	155	142	145	147	160		
	Annual Additions, Short Term Resources	175	1,239	1,425	1,341	772	900	950	566	700	950	630	771	883	938	1,244	1,422	1,577	1,696	1,883	2,002		
	Total Annual Additions	313	1,457	1,625	2,366	1,664	1,062	1,093	1,316	855	1,200	769	913	1,024	1,084	1,553	1,577	1,719	1,842	2,030	2,162		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.
** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.10 – Renewable Resource Sensitivity Cases (28 to 30a)

Case 28

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	5	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	47	54	59	43	44	51	52	53	56	60	56	60	57	60	60	65	60	63	64	72	519	1,135
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	50	58	64	49	51	58	60	63	66	69	67	71	70	76	77	86	82	89	95	102	589	1,403
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	190	200	200	17	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	105	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	56	100	114	154	100	159	154	138	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	287	343	346	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	-	342	213	340	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	8	11	6	6	7	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	147
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,254
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	-	-	-	-	-	-	-	-	-	-	16	16
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	298	400	400	400	366	400	-	268	377	395	400	400	400	400	400	400	346	345
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	21	-	-	165	128	180	-	156	155	N/A	80
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	327	-	-	-	N/A	33
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	315	145	126	111	222	259	208	142	236	237	N/A	200
	Annual Additions, Long Term Resources	162	200	200	777	837	157	152	144	614	197	138	142	141	147	148	155	142	141	152	154		
	Annual Additions, Short Term Resources	340	1,213	1,420	1,181	648	770	803	944	666	950	621	754	859	906	1,201	1,369	1,515	1,631	1,801	1,915		
	Total Annual Additions	502	1,412	1,620	1,957	1,485	927	955	1,088	1,279	1,147	759	895	999	1,053	1,349	1,524	1,657	1,772	1,953	2,068		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 29

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	8	9	4	34	-	58
Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	4	8	9	4	34	-	218
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	-	-	-	-	-	-	-	-	-	5	-	92	97
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	47	54	59	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	500	1,113
DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	55	229
DSM, Class 2 Total	50	58	64	48	51	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	568	1,380
Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
FOT Mead 3rd Qtr HLH	-	168	264	264	-	24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	190	200	200	17	-	-	57	200	-	193	-	-	-	-	-	-	-	-	-	-	106	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	36	83	141	158	100	156	162	138	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	-	269	362	336	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	-	366	212	341	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	58	58
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
DSM, Class 2, Yakima	8	11	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	70	145
DSM, Class 2 Total	63	66	65	70	71	70	70	63	63	63	64	65	65	66	66	64	54	47	47	47	665	1,249
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-	15	16
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	299	400	400	400	376	400	117	281	389	400	400	400	400	400	400	400	347	353
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	2	-	-	101	75	165	-	92	161	N/A	59
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	317	-	-	-	N/A	32
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	190	144	126	115	252	315	226	134	265	234	N/A	200
Annual Additions, Long Term Resources	162	200	200	776	837	153	150	140	607	216	139	142	141	147	308	159	150	150	155	185		
Annual Additions, Short Term Resources	340	1,213	1,420	1,181	649	774	807	950	676	943	613	746	851	898	1,193	1,362	1,508	1,624	1,794	1,909		
Total Annual Additions	502	1,412	1,620	1,957	1,486	927	957	1,090	1,283	1,158	753	888	992	1,045	1,501	1,520	1,658	1,773	1,949	2,093		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 30

	Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	4	48	21	8	9	4	34	-	127
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	4	48	21	8	9	4	34	-	127
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	5	-	97	102
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	47	53	59	43	44	48	52	53	55	60	56	60	57	60	60	65	60	63	64	69	514	1,127
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
	DSM, Class 2 Total	50	57	64	49	51	56	60	62	64	69	67	71	70	76	77	86	82	89	95	99	584	1,395
	Micro Solar - Photovoltaic	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	-	-	12	22
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	-	-	-	-	-	24	37
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	190	200	200	16	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	105	53
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	51	92	151	154	100	145	144	137	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	308	352	316	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34	103	-	303	258	302	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
	DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	146
	DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,253
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.3	1.0	1.0	-	-	-	-	-	16	22
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	366	400	-	266	377	395	400	400	400	400	400	400	346	345
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	20	-	-	30	25	164	-	21	168	N/A	43
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	258	-	-	-	N/A	26
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	313	145	125	111	215	290	223	103	253	222	N/A	200
	Annual Additions, Long Term Resources	163	200	201	778	838	155	153	145	613	198	144	147	146	156	271	177	151	150	155	185		
	Annual Additions, Short Term Resources	340	1,213	1,420	1,180	647	771	803	944	666	950	619	750	853	898	1,129	1,298	1,443	1,559	1,729	1,844		
	Total Annual Additions	503	1,412	1,621	1,958	1,485	926	956	1,088	1,280	1,148	763	897	999	1,054	1,401	1,474	1,594	1,709	1,884	2,029		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 30a

	Capacity (MW)																				Resource Totals **	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	7	49	21	8	9	4	34	-	132
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	7	49	21	8	9	4	34	-	132
CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
DSM, Class 1, Utah-DLC-Residential	21	11	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	37	37
DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1 Total	26	41	-	20	-	-	5	-	-	5	-	-	-	-	-	-	-	-	5	-	97	102
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
DSM, Class 2, Utah	47	53	59	43	44	48	52	53	55	60	56	60	57	60	60	65	60	63	64	69	514	1,127
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	56	230
DSM, Class 2 Total	50	57	64	49	51	56	60	62	64	69	67	71	70	76	77	86	82	89	95	99	584	1,395
Micro Solar - Photovoltaic	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	-	-	-	-	-	-	-	-	-	-	12	12
Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	-	-	-	-	-	24	37
FOT Mead 3rd Qtr HLH	-	168	264	264	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
FOT Utah 3rd Qtr HLH	190	200	200	16	-	-	53	194	-	200	-	-	-	-	-	-	-	-	-	-	105	53
FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	6	20	52	93	151	154	100	145	142	137	N/A	100
Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	-	309	358	306	N/A	100
Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	100	-	303	257	315	N/A	100
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	70	105
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4	4
DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	50	-	-	-	6	-	-	4	-	-	-	-	-	-	-	-	-	-	60	60
DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	551	1,016
DSM, Class 2, Yakima	8	11	6	6	6	7	7	7	7	7	8	8	8	9	9	7	6	7	6	7	72	146
DSM, Class 2 Total	63	66	66	70	72	71	71	63	63	64	64	65	65	66	66	64	54	47	47	47	669	1,253
Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.3	1.0	1.0	-	-	-	-	-	16	22
FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
FOT MidColumbia 3rd Qtr HLH	-	400	400	400	297	400	400	400	366	400	-	266	377	396	400	400	400	400	400	400	346	345
FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	244	206	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	23
FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	20	-	-	40	28	167	-	23	169	N/A	45
Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	-	-	-	N/A	26
Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	313	145	125	111	216	291	219	106	253	220	N/A	200
Annual Additions, Long Term Resources	163	200	201	778	838	155	153	145	613	198	142	146	145	157	270	176	150	150	155	185		
Annual Additions, Short Term Resources	340	1,213	1,420	1,180	647	771	803	944	666	950	620	751	854	900	1,132	1,300	1,447	1,562	1,733	1,848		
Total Annual Additions	503	1,412	1,621	1,958	1,485	926	956	1,088	1,280	1,148	762	896	999	1,057	1,402	1,476	1,596	1,712	1,888	2,032		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Table D.11 – Demand-Side Management Sensitivity Cases (31 to 33)

Case 31

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	4	34	-	55
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	8	9	4	34	-	215
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 3, Goshen, Critical Peak Pricing, Comm/Indu	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 3, Goshen, Time of Use, Irrigation	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 3, Utah, Critical Peak Pricing, Comm/Indus	-	-	-	19	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	28	28
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 3, Utah, Demand Buyback, Comm/Indus	-	6	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, Utah-DLC-Residential	-	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29	29
	DSM, Class 3, Utah, Real-Time Pricing, Comm/Indus	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 3, Utah, Time of Use, Irrigation	-	-	-	117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	117
	DSM, Class 3, Wyoming, Critical Peak Pricing, Comm/In	-	-	-	11	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 3, Wyoming, Demand Buyback, Comm/Indus	-	5	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	10	10
	DSM, Class 3, Wyoming, Real-Time Pricing, Comm/Indus	-	-	-	3	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 3, Wyoming, Time of Use, Irrigation	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	DSM, Class 1 Total	6	66	-	221	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	322	322
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	58	65	64	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	526	1,140
	DSM, Class 2, Wyoming	3	4	4	4	5	5	6	7	7	8	9	9	11	13	14	18	20	23	29	28	54	228
	DSM, Class 2 Total	61	70	70	48	50	54	57	59	61	64	67	71	70	76	77	86	82	89	95	99	595	1,406
	Micro Solar - Water Heater	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.37	-	-	-	-	-	-	-	-	24	28
	FOT Mead 3rd Qtr HLH	-	168	264	204	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	37
	FOT Utah 3rd Qtr HLH	-	178	200	-	151	-	-	88	194	82	-	-	-	-	-	-	-	-	-	-	89	45
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	3	38	54	133	177	76	210	194	116	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	282	355	319	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	190	229	254	296	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Oregon/California-Curtailment	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	16
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, Oregon, Critical Peak Pricing, Comm/Indu	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 3, California, Time of Use, Irrigation	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 3, Oregon, Time of Use, Irrigation	-	-	-	72	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	72
	DSM, Class 3, Walla Walla, Time of Use, Irrigation	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 3, Yakima, Time of Use, Irrigation	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21
	DSM, Class 1 Total	-	-	23	131	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	155	155
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	55	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	6	6	7	62	136
	DSM, Class 2 Total	61	62	65	70	71	70	70	62	63	63	64	65	65	66	66	64	54	46	47	47	657	1,241
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	0.82	-	-	-	-	-	-	15	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	15	400	400	400	400	348	394	400	400	400	202	330	400	400	400	400	400	400	400	400	356	364
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	-	50	-	-	50	50	50	-	-	-	-	-	-	-	-	-	-	30	15
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	104	123	-	-	172	N/A	42
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	189	206	229	58	151	167	N/A	100
	Annual Additions, Long Term Resources	150	232	179	1,108	239	749	137	140	178	640	142	145	142	182	308	155	150	149	150	185		
	Annual Additions, Short Term Resources	165	1,217	1,425	1,054	1,051	648	694	838	944	832	502	633	738	754	1,048	1,217	1,363	1,479	1,654	1,769		
	Total Annual Additions	316	1,449	1,604	2,163	1,290	1,397	831	977	1,122	1,472	643	778	879	936	1,357	1,372	1,513	1,629	1,804	1,954		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 32

	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource Totals ** 10-year	Resource Totals ** 20-year
		Capacity (MW)																					
East																							
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	-	7
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	7	-	167
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	-	-	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	1	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	25
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32	32
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	11	14
	DSM, Class 1 Total	6	58	-	21	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	87	92
	DSM, Class 2, Goshen	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	16	45
	DSM, Class 2, Utah	54	59	55	54	57	61	63	65	67	71	75	80	77	79	79	87	81	85	85	92	608	1,428
	DSM, Class 2, Wyoming	4	5	5	6	6	6	8	9	9	9	11	12	14	17	18	23	24	29	36	35	67	284
	DSM, Class 2 Total	59	65	61	61	65	70	74	76	78	83	88	94	93	99	100	113	108	117	124	129	691	1,758
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-	-	-	-	-	-	-	-	-	-	24	24
	FOT Mead 3rd Qtr HLH	-	168	264	264	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	40
	FOT Utah 3rd Qtr HLH	-	194	200	-	200	-	-	91	181	81	-	-	-	-	-	-	-	-	-	-	95	47
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	13	70	66	91	222	155	139	133	111	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	202	205	N/A	58
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	212	233	349	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Utility Biomass	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	6	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	57	57
	DSM, Class 2, Walla Walla	5	5	5	5	5	5	5	5	5	5	5	6	6	6	6	5	4	4	4	4	48	98
	DSM, Class 2, Oregon/California	51	52	55	59	61	60	59	52	52	52	52	52	52	53	53	52	45	37	37	37	552	1,020
	DSM, Class 2, Yakima	7	7	8	8	8	7	8	8	8	8	9	10	10	10	10	8	7	8	8	8	76	164
	DSM, Class 2 Total	63	63	67	72	73	72	72	64	64	65	66	68	68	68	69	66	56	49	48	49	677	1,283
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.0	1.0	1.0	-	-	-	-	-	-	-	-	15	17
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	18	400	400	400	400	382	400	400	400	400	-	-	-	21	400	400	400	400	400	400	360	301
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	269	208	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	50	-	14	50	50	50	-	-	-	-	-	-	-	-	-	-	36	18
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	182	280	307	316	155	168	152	82	186	173	N/A	200
	Annual Additions, Long Term Resources	148	219	198	798	309	766	155	158	197	632	163	168	166	173	369	184	170	171	178	195		
	Annual Additions, Short Term Resources	168	1,231	1,422	1,164	1,099	682	714	841	931	831	482	593	677	703	946	1,090	1,213	1,304	1,454	1,538		
	Total Annual Additions	316	1,451	1,621	1,962	1,408	1,448	869	1,000	1,129	1,463	645	761	843	876	1,315	1,274	1,383	1,475	1,632	1,733		

* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Case 33

		Capacity (MW)																				Resource Totals **	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1	-	-	-	625	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT H	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Geothermal, Blundell 3	-	-	-	-	35	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	80	80
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	35	35
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	9	4	34	-	55
	Wind, Wyoming NE, 35% Capacity Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	160
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	160	-	8	9	4	34	-	215
	CHP - Biomass	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	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	DSM, Class 1, Utah-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, Goshen-DLC-Irrigation	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	8	10
	DSM, Class 1, Utah-Curtailment	-	21	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	26	26
	DSM, Class 1, Utah-DLC-Residential	-	32	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	34	34
	DSM, Class 1, Utah-DLC-Irrigation	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	11	14
	DSM, Class 1, Utah-Sched Therm Energy Storage	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1 Total	6	62	-	20	-	-	8	-	-	-	-	-	-	-	-	-	-	-	5	-	95	99
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	2	14	38
	DSM, Class 2, Utah	46	55	59	43	44	47	49	50	52	54	56	60	57	60	60	65	60	63	64	69	499	1,113
	DSM, Class 2, Wyoming	3	4	4	4	5	6	6	7	7	8	9	9	11	13	14	18	20	23	29	28	55	229
	DSM, Class 2 Total	49	59	64	48	51	55	57	59	61	64	67	71	70	76	77	86	82	89	95	99	568	1,380
	Micro Solar - Water Heater	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	2.4	0.0	-	-	-	-	-	-	-	24	29
	FOT Mead 3rd Qtr HLH	-	168	264	264	-	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah 3rd Qtr HLH	-	200	200	22	-	-	57	200	-	193	-	-	-	-	-	-	-	-	-	-	87	44
	FOT Mona-3 3rd Qtr HLH	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 3rd Qtr HLH	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
	Growth Resource Goshen *	-	-	-	-	-	-	-	-	-	-	-	-	34	80	184	237	-	238	170	57	N/A	100
	Growth Resource Utah North *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	306	335	358	N/A	100
	Growth Resource Wyoming *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	-	262	290	395	N/A	100
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	0.3	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Residential	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, Walla Walla-DLC-Irrigation	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, Oregon/California-Curtailment	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	17
	DSM, Class 1, Oregon/California-DLC-Residential	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, Oregon/California-DLC-Water Heater	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Oregon/California-DLC-Irrigation	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, Yakima-DLC-Residential	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, Yakima-DLC-Irrigation	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	50	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	DSM, Class 2, Walla Walla	4	4	5	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	4	4	45	90
	DSM, Class 2, Oregon/California	51	51	54	59	60	60	59	52	52	52	52	52	52	52	52	52	44	36	36	36	550	1,015
	DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	8	8	9	9	7	6	7	6	7	63	138
	DSM, Class 2 Total	61	62	65	70	71	70	70	63	63	63	64	65	65	66	66	64	54	47	47	47	658	1,243
	Distribition Energy Efficiency, Walla Walla	-	-	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Distribition Energy Efficiency, Yakima	-	-	-	-	-	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	Oregon Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	Oregon Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Water Heater	-	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.3	1.3	1.0	1.0	1.0	1.0	-	-	-	-	-	-	15	19
	FOT COB 3rd Qtr HLH	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	33
	FOT MidColumbia 3rd Qtr HLH	25	400	400	400	303	400	400	400	376	400	98	290	388	400	400	400	400	400	400	400	350	354
	FOT MidColumbia 3rd Qtr HLH 10% Price Premium	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South Central Oregon/Northern California 3rd Qtr HLH	-	50	50	50	-	50	50	50	-	50	-	-	-	-	-	-	-	-	-	-	35	18
	Growth Resource Walla Walla *	-	-	-	-	-	-	-	-	-	-	-	12	-	-	56	52	167	-	32	164	N/A	48
	Growth Resource Oregon/California *	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	412	-	-	-	N/A	41
	Growth Resource Yakima *	-	-	-	-	-	-	-	-	-	-	214	142	126	115	250	316	226	115	264	231	N/A	200
	Annual Additions, Long Term Resources	138	217	200	776	837	153	155	140	607	216	142	145	142	148	308	155	150	150	155	185		
	Annual Additions, Short Term Resources	175	1,239	1,425	1,186	653	778	807	950	676	943	612	744	848	895	1,190	1,358	1,505	1,621	1,791	1,906		
	Total Annual Additions	313	1,456	1,625	1,962	1,490	931	961	1,090	1,283	1,159	754	889	990	1,043	1,498	1,513	1,655	1,770	1,946	2,091		

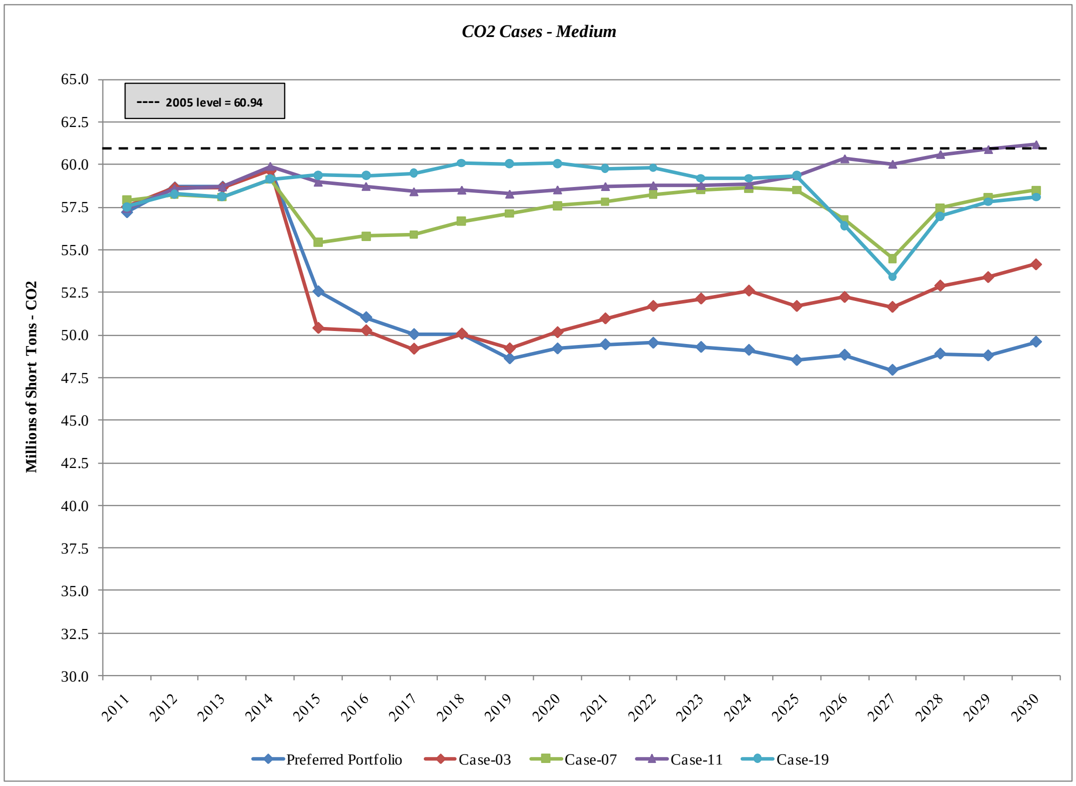
* Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

** Front office transactions are reported as a 20-year annual average. Growth resources are reported as a 10-year average.

Annual Carbon Dioxide Emission Trends

Figure D.1 shows the Preferred Portfolio added to the medium CO2 emission profile chart from Chapter 8.

Figure D.1 – Core Cases: CO_2 Emission Profile for Medium CO_2 Tax Costs



APPENDIX E – STOCHASTIC PRODUCTION COST SIMULATION RESULTS

This appendix reports additional results for the Monte Carlo production cost simulations conducted with PacifiCorp's Planning and Risk (PaR) model, including certain sensitivity portfolios: coal utilization cases 20 through 24, and high/low economic growth cases 25 and 26. These results supplement the data presented in Chapter 8 of the main IRP document. The results presented include the following:

- Stochastic mean PVRR versus upper-tail mean PVRR scatter-plot diagrams that include all CO_2 hard cap portfolios
- The full complement of stochastic risk and other portfolio performance measures for the portfolios simulated using PaR.
- Stochastic mean PVRR component cost details for the portfolios.

Core Case Study Stochastic Results

Mean versus Upper-tail Mean PVRR Scatter-plot Charts

The following set of scatter-plot charts incorporates all 19 core cases. The scatter-plot charts in Chapter 8 excluded a number of the CO_2 emission hard cap portfolios due to high PVRRs that impacted axis scaling and legibility of the data points.

Figure E.1 – Stochastic Cost versus Upper-tail Risk, Zero CO_2 Tax Scenario

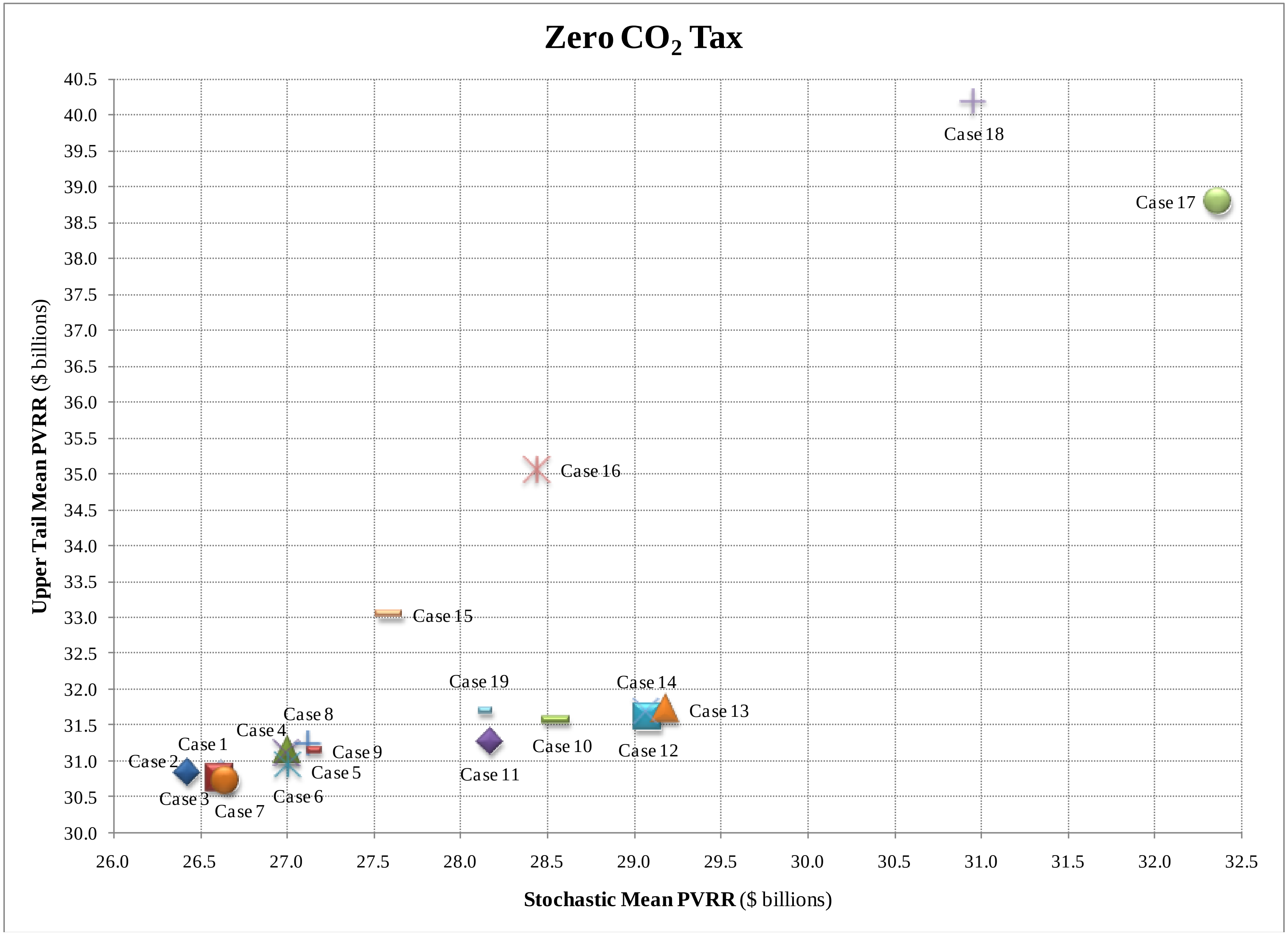


Figure E.2 – Stochastic Cost versus Upper-tail Risk, Medium CO_2 Tax Scenario

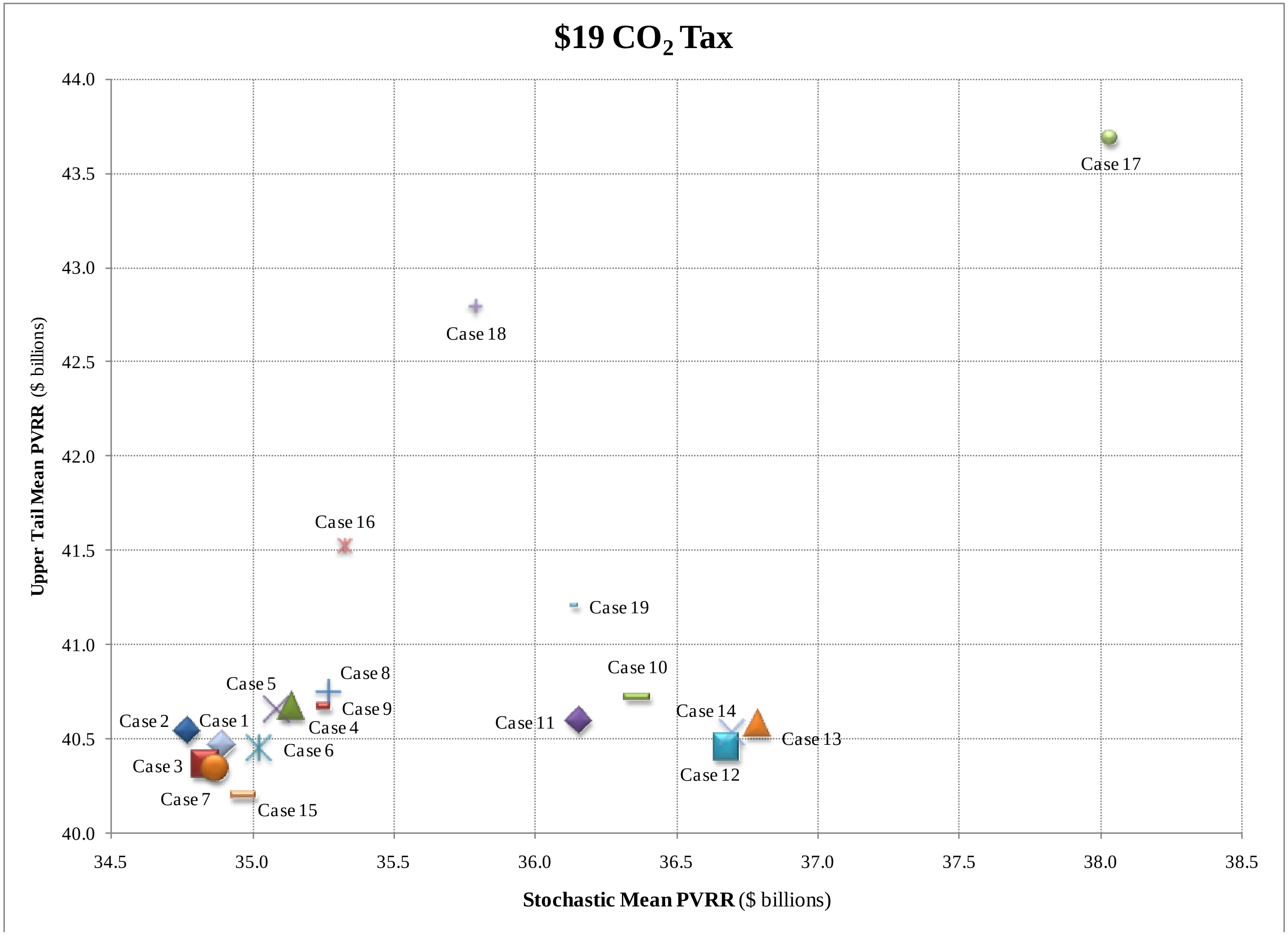


Figure E.3 – Stochastic Cost versus Upper-tail Risk, Low to Very High CO_2 Tax Scenario

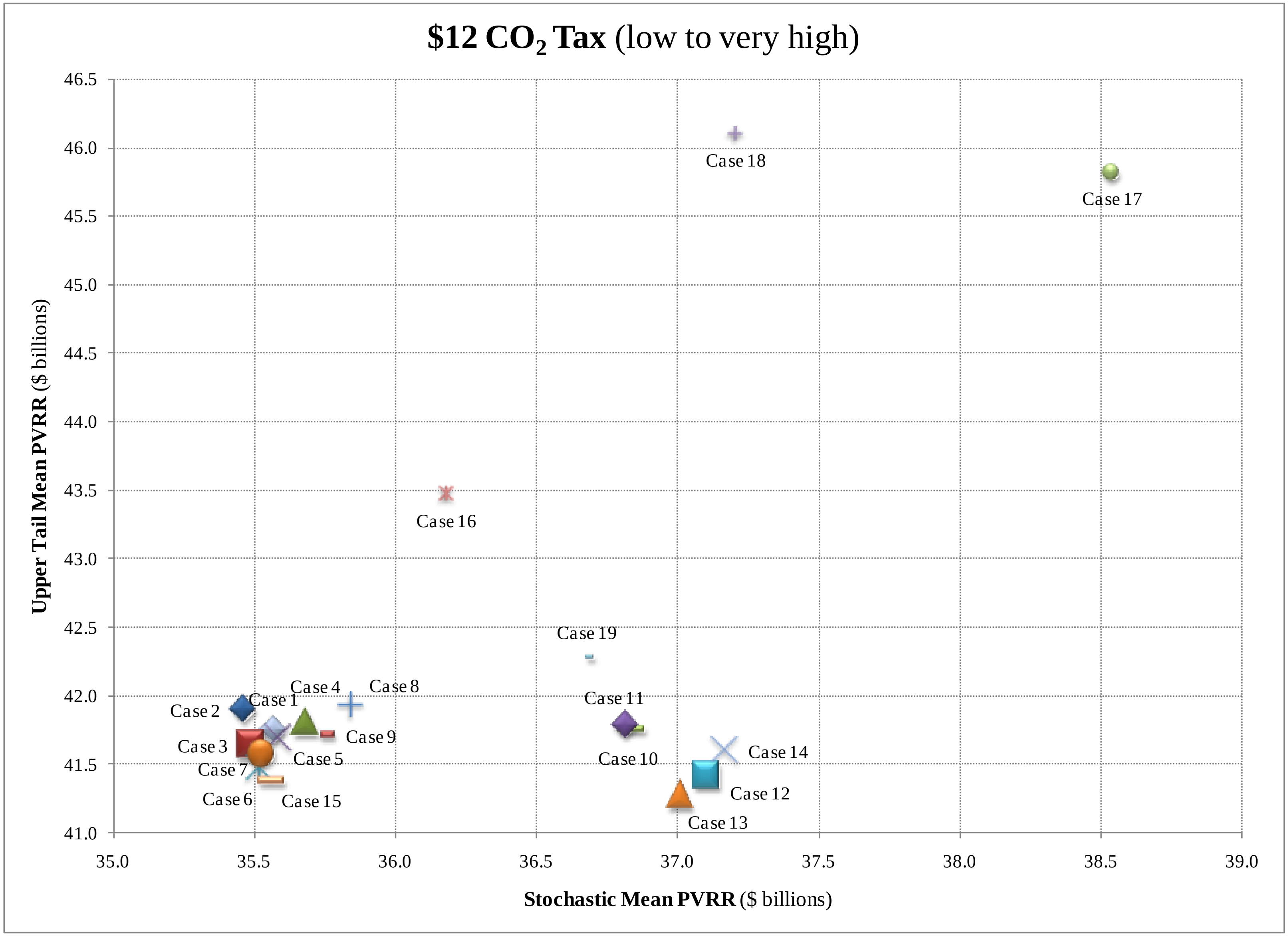


Figure E.4 – Stochastic Cost versus Upper-tail Risk, Average for CO_2 Tax Scenarios

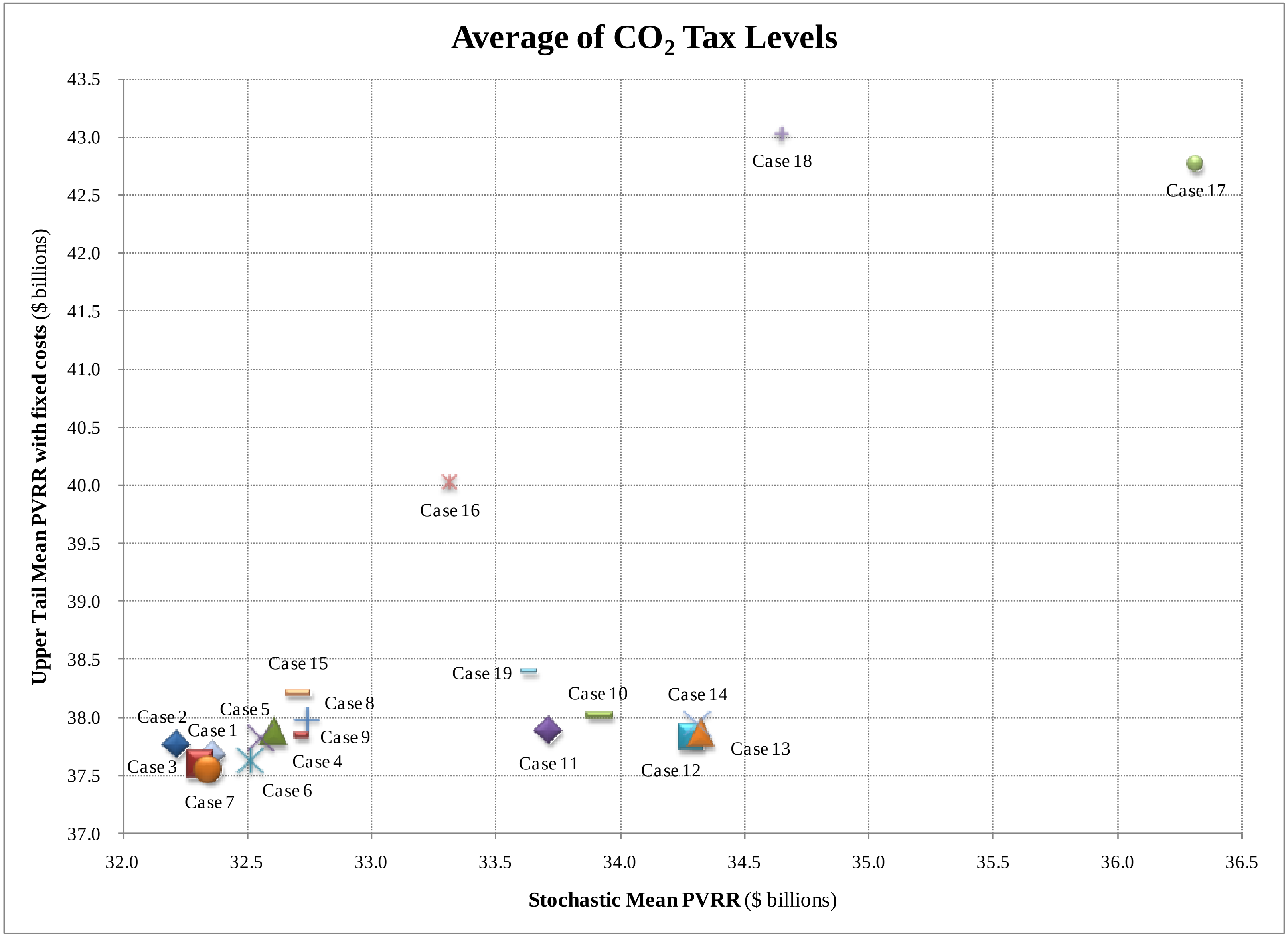


Table E.1– Stochastic Mean PVRR by CO_2 Tax Level, Core Case Portfolios

	CO_2 tax level Million Dollars (2011$)			
Case	**$0/ton**	**$12/ton** (low to very high)	**$19/ton**	**Average**
Case 1	26,623	35,567	34,892	32,360
Case 2	26,424	35,462	34,768	32,218
Case 3	26,616	35,488	34,835	32,313
Case 4	27,002	35,681	35,139	32,607
Case 5	27,000	35,585	35,087	32,558
Case 6	27,008	35,516	35,024	32,516
Case 7	26,650	35,527	34,868	32,348
Case 8	27,122	35,841	35,271	32,744
Case 9	27,122	35,738	35,231	32,697
Case 10	28,555	36,838	36,362	33,918
Case 11	28,172	36,816	36,154	33,714
Case 12	29,082	37,103	36,678	34,288
Case 13	29,182	37,009	36,789	34,327
Case 14	29,073	37,167	36,698	34,312
Case 15	27,591	35,560	34,969	32,707
Case 16	28,441	36,181	35,328	33,317
Case 17	32,369	38,539	38,036	36,315
Case 18	30,957	37,206	35,791	34,651
Case 19	28,108	36,679	36,128	33,638

Table E.2 – Stochastic Risk Results by CO_2 Tax Level, Core Case Portfolios

	CO_2 tax level: $0/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Case 1	1,948	23,551	29,799	30,808
Case 2	2,029	23,289	29,825	30,836
Case 3	1,934	23,563	29,796	30,752
Case 4	1,954	23,892	30,191	31,139
Case 5	1,974	23,836	30,194	31,092
Case 6	1,919	23,901	30,093	30,938
Case 7	1,915	23,604	29,784	30,727
Case 8	1,930	24,066	30,277	31,232
Case 9	1,918	24,031	30,239	31,140
Case 10	1,515	25,956	30,751	31,556
Case 11	1,550	25,530	30,601	31,267
Case 12	1,351	26,681	30,984	31,603
Case 13	1,337	26,817	31,096	31,715
Case 14	1,368	26,678	31,099	31,678
Case 15	3,094	22,909	32,060	33,036
Case 16	3,852	22,803	34,100	35,053
Case 17	3,702	27,139	37,948	38,792

	CO_2 tax level: $0/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Case 18	5,372	23,619	39,270	40,182
Case 19	1,754	25,198	30,890	31,688

	CO_2 tax level: $12/ton (low to very high) Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Case 1	3,538	30,185	40,773	41,748
Case 2	3,629	29,986	40,833	41,897
Case 3	3,530	30,116	40,643	41,639
Case 4	3,535	30,308	40,860	41,801
Case 5	3,588	30,125	40,857	41,685
Case 6	3,537	30,112	40,621	41,470
Case 7	3,497	30,198	40,653	41,578
Case 8	3,492	30,527	40,943	41,929
Case 9	3,485	30,425	40,852	41,709
Case 10	2,992	32,117	40,806	41,749
Case 11	3,031	32,052	41,074	41,787
Case 12	2,779	32,666	40,627	41,417
Case 13	2,710	32,664	40,457	41,270
Case 14	2,794	32,693	40,772	41,597
Case 15	3,366	30,376	40,526	41,375
Case 16	4,362	29,774	42,618	43,469
Case 17	4,271	32,485	44,974	45,819
Case 18	5,419	29,490	45,353	46,097
Case 19	3,378	31,435	41,467	42,276

	CO_2 tax level: $19/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Case 1	3,109	30,050	39,270	40,465
Case 2	3,204	29,836	39,513	40,542
Case 3	3,103	30,012	39,230	40,360
Case 4	3,115	30,300	39,523	40,667
Case 5	3,158	30,177	39,517	40,653
Case 6	3,111	30,173	39,350	40,445
Case 7	3,076	30,080	39,198	40,342
Case 8	3,080	30,479	39,618	40,747
Case 9	3,070	30,426	39,534	40,666
Case 10	2,573	32,206	39,619	40,718
Case 11	2,612	31,976	39,524	40,592
Case 12	2,390	32,783	39,859	40,452

	CO_2 tax level: $19/ton Million Dollars (2011$)			
Case	Production cost standard deviation	5th percentile	95th percentile	Upper-tail mean
Case 13	2,365	32,896	39,979	40,576
Case 14	2,391	32,821	39,968	40,528
Case 15	2,806	30,683	39,117	40,197
Case 16	3,543	29,877	40,405	41,519
Case 17	3,381	32,874	42,757	43,692
Case 18	4,210	29,456	41,637	42,791
Case 19	2,960	31,450	40,155	41,203

Table E.3 – Carbon Dioxide and Other Pollutant Emissions

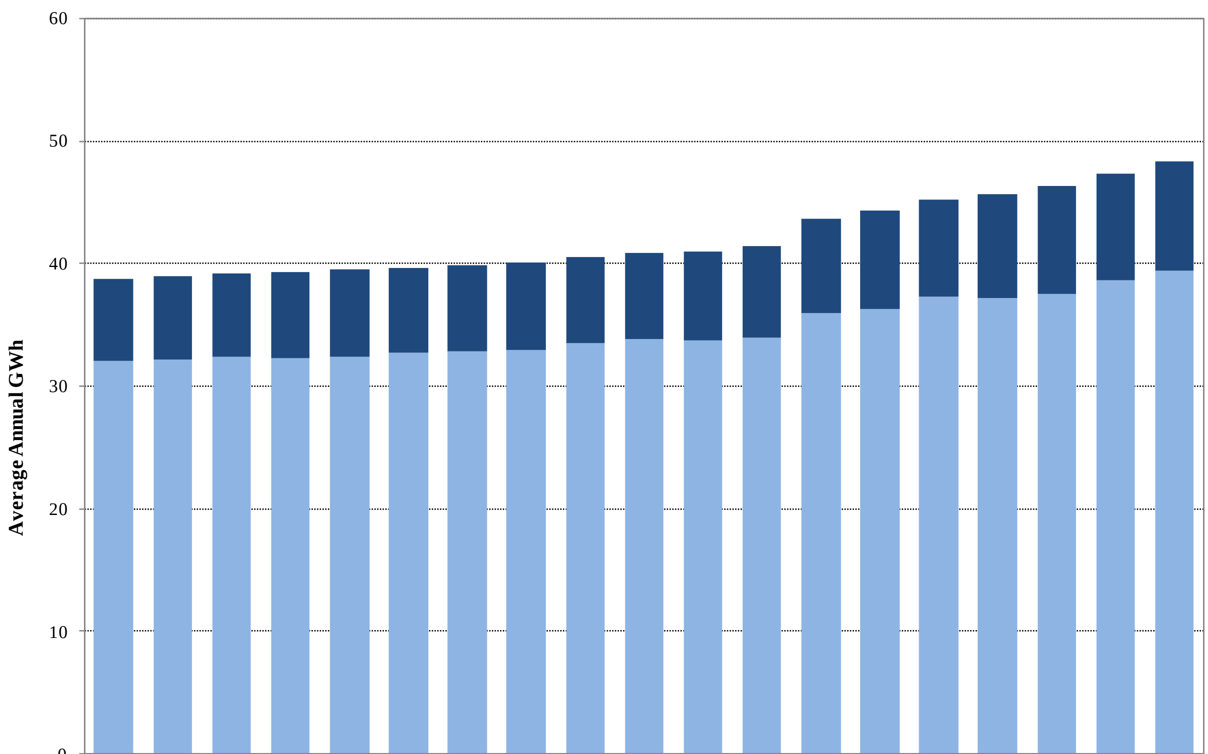
	Emissions				Emissions				Emissions			
	CO2	SO2	NOx	Hg	CO2	SO2	NOx	Hg	CO2	SO2	NOx	Hg
	000 Tons	000 Tons	000 Tons	Pounds	000 Tons	000 Tons	000 Tons	Pounds	000 Tons	000 Tons	000 Tons	Pounds
Case	$0 CO2 Tax				$19 CO2 Tax				$12 Low to Very High CO2 Tax			
1	941,203	753	1,092	6,289	842,439	653	939	5,700	801,497	641	912	5,492
2	943,810	754	1,093	6,298	847,689	656	944	5,721	807,175	644	918	5,516
3	937,901	751	1,087	6,277	837,918	649	932	5,681	796,784	638	906	5,473
4	930,958	745	1,075	6,389	829,216	643	918	5,881	787,440	631	891	5,697
5	929,942	740	1,066	6,338	826,233	635	906	5,813	782,864	622	877	5,637
6	924,985	737	1,061	6,320	820,706	631	900	5,791	777,600	619	872	5,618
7	938,503	752	1,088	6,280	838,639	650	933	5,683	797,611	638	907	5,476
8	931,497	748	1,079	6,433	830,673	646	923	5,912	789,817	635	897	5,722
9	930,726	745	1,074	6,369	828,225	642	916	5,860	785,834	630	889	5,683
10	917,430	747	1,076	6,363	807,771	641	912	5,834	764,891	627	882	5,648
11	932,265	756	1,095	6,293	825,486	651	934	5,672	784,279	638	906	5,462
12	907,039	741	1,067	6,347	793,839	631	898	5,792	751,203	618	869	5,595
13	906,120	742	1,068	6,282	793,834	633	900	5,735	750,460	620	871	5,559
14	911,849	742	1,067	6,322	799,548	633	900	5,771	755,998	618	869	5,591
15	814,681	645	916	5,875	859,920	670	958	6,029	800,509	639	905	5,736
16	770,990	604	854	5,634	810,905	626	890	5,766	746,912	586	828	5,434
17	673,465	543	766	5,253	711,580	566	803	5,377	651,663	525	745	5,062
18	677,562	506	709	5,114	757,444	568	804	5,447	682,971	516	723	5,068
19	922,446	740	1,068	6,219	821,231	636	911	5,610	779,075	623	883	5,393

Table E.4 – Cumulative 10-year Customer Rate Impact, Core Case Portfolios

Case	$0 CO_2	$ 19 CO_2	$ 12 CO_2 (low - very high)	Average	Rank
1	22.6%	39.6%	33.6%	31.9%	3
2	22.3%	39.4%	33.3%	31.7%	1
3	22.6%	39.5%	33.5%	31.9%	2
4	22.9%	39.8%	33.8%	32.2%	6
5	22.7%	39.6%	33.6%	32.0%	5
6	23.3%	39.9%	34.0%	32.4%	9
7	22.7%	39.6%	33.6%	31.9%	4
8	23.0%	40.0%	33.9%	32.3%	8
9	22.9%	39.9%	33.8%	32.2%	7
10	27.3%	43.4%	37.8%	36.2%	17
11	26.3%	42.6%	36.9%	35.2%	13

Case	$0 CO_2	$ 19 CO_2	$ 12 CO_2 (low - very high)	Average	Rank
12	26.9%	43.0%	37.5%	35.8%	16
13	26.3%	42.6%	36.9%	35.2%	14
14	28.3%	44.0%	38.7%	37.0%	18
15	24.1%	39.6%	33.8%	32.5%	10
16	26.0%	39.9%	35.3%	33.7%	11
17	33.4%	45.0%	41.6%	40.0%	19
18	29.5%	40.6%	37.1%	35.7%	15
19	25.5%	42.3%	36.3%	34.7%	12

Figure E.5 – Average Annual Energy Not Served (2011 – 2030), $19 CO_2 Core Case Portfolios



	C05	C06	C18	C13	C09	C16	C17	C10	C14	C15	C04	C12	C19	C03	C08	C07	C11	C01	C02
West	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	9	9	9
East	32	32	32	32	32	33	33	33	34	34	34	34	36	36	37	37	37	39	39

Table E.5 – Loss of Load Probability for a Major (> 25,000 MWh) July Event, Core Case Portfolios

Year	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
2011	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
2012	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
2013	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
2014	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
2015	13%	12%	12%	12%	12%	12%	12%	12%	12%	13%
2016	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
2017	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
2018	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
2019	26%	26%	26%	26%	26%	26%	26%	25%	26%	25%
2020	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%
2021	24%	24%	24%	24%	24%	24%	24%	24%	24%	24%
2022	21%	21%	21%	21%	21%	21%	17%	21%	18%	19%
2023	9%	13%	16%	16%	16%	16%	6%	16%	15%	16%
2024	21%	18%	27%	17%	33%	33%	16%	33%	27%	33%
2025	18%	14%	23%	21%	17%	26%	23%	26%	26%	26%
2026	17%	16%	13%	13%	14%	14%	20%	13%	21%	20%
2027	24%	27%	27%	28%	19%	16%	28%	19%	28%	28%
2028	31%	31%	24%	25%	16%	16%	30%	24%	25%	23%
2029	39%	39%	33%	37%	24%	24%	38%	30%	24%	21%
2030	50%	51%	49%	39%	35%	35%	50%	47%	28%	29%

Year	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19
2011	7%	7%	7%	7%	7%	7%	7%	7%	7%
2012	6%	6%	6%	6%	6%	6%	6%	6%	6%
2013	8%	8%	8%	8%	8%	8%	8%	8%	8%
2014	10%	10%	10%	10%	10%	10%	10%	10%	10%
2015	13%	13%	13%	13%	12%	12%	13%	12%	13%
2016	10%	10%	10%	10%	10%	10%	10%	10%	10%
2017	19%	19%	19%	19%	19%	19%	19%	19%	19%
2018	27%	27%	27%	27%	27%	27%	27%	27%	27%
2019	25%	25%	25%	25%	25%	26%	25%	25%	26%
2020	21%	21%	21%	21%	21%	21%	21%	21%	21%
2021	24%	20%	24%	24%	24%	24%	24%	24%	24%
2022	18%	13%	19%	21%	21%	21%	21%	6%	22%
2023	13%	11%	14%	16%	16%	16%	16%	2%	16%
2024	25%	27%	24%	33%	32%	19%	32%	32%	32%
2025	15%	15%	15%	19%	26%	17%	14%	26%	26%
2026	15%	16%	16%	12%	13%	11%	13%	21%	14%
2027	28%	28%	23%	12%	14%	27%	25%	27%	23%
2028	29%	29%	23%	27%	18%	20%	20%	22%	20%
2029	36%	37%	32%	33%	28%	32%	27%	32%	37%
2030	50%	46%	36%	36%	43%	39%	43%	35%	48%

Table E.6 – Average Loss of Load Probability During Summer Peak

Average for operating years 2011 through 2020										
Event Size (MWh)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
> 0	92%	93%	93%	93%	93%	93%	93%	93%	93%	93%
> 1,000	75%	75%	75%	75%	75%	74%	75%	75%	75%	75%
> 10,000	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
> 25,000	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
> 50,000	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
> 100,000	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2011 through 2030										
Event Size (MWh)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
> 0	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
> 1,000	73%	74%	74%	74%	74%	74%	74%	74%	74%	76%
> 10,000	32%	32%	32%	31%	31%	31%	31%	32%	31%	31%
> 25,000	20%	20%	20%	19%	18%	19%	20%	20%	19%	19%
> 50,000	11%	11%	11%	10%	9%	10%	11%	10%	10%	10%
> 100,000	4%	4%	4%	3%	3%	3%	4%	3%	3%	3%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Average for operating years 2011 through 2020									
Event Size (MWh)	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19
> 0	93%	93%	93%	93%	92%	92%	92%	92%	92%
> 1,000	75%	75%	75%	75%	74%	74%	74%	74%	75%
> 10,000	26%	26%	26%	26%	26%	26%	26%	26%	26%
> 25,000	15%	15%	15%	15%	15%	15%	15%	15%	15%
> 50,000	6%	6%	6%	6%	6%	6%	6%	6%	6%
> 100,000	2%	2%	2%	2%	2%	2%	2%	2%	2%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2011 through 2030									
Event Size (MWh)	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19
> 0	92%	92%	92%	93%	92%	92%	93%	92%	92%
> 1,000	74%	74%	74%	76%	74%	74%	74%	73%	75%
> 10,000	31%	31%	31%	31%	31%	31%	31%	31%	32%
> 25,000	20%	19%	19%	19%	19%	19%	19%	19%	20%
> 50,000	11%	10%	10%	10%	10%	10%	10%	10%	11%
> 100,000	4%	3%	3%	3%	3%	3%	3%	3%	3%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%	0%

Coal Plant Utilization Sensitivity and Load Forecast Scenario Stochastic Study Results

The following tables report stochastic production cost modeling results for Cases 21 through 24 (coal utilization sensitivities) and Cases 25 and 26 (low and high economic growth sensitivities). Note that the Case 20 coal utilization portfolio (medium CO_2 tax and gas prices) did not result in any coal plant replacements, so the Company did not consider it worthwhile to conduct a stochastic production cost simulation with this portfolio. Similarly, the Case 27 portfolio, which assumed high peak loads driven by one-in-ten peak load producing temperatures, was not sufficiently different in resource mix relative to the high economic growth portfolio to warrant stochastic production cost modeling.

Table E.7 – Stochastic Mean PVRR by CO_2 Tax Level, Sensitivity Portfolios

	CO_2 tax level Million Dollars (2011$)			
Case	**$0/ton**	**$12/ton** (low to very high)	**$19/ton**	**Average**
Coal Plant Utilization Sensitivity Cases				
Case 21	26,648	35,495	34,857	32,334
Case 22	27,053	35,877	35,241	32,724
Case 23	27,553	36,079	35,561	33,064
Case 24	27,976	36,499	35,529	33,335
Load Forecast Sensitivity Cases				
Case 25	25,142	33,710	34,071	30,974
Case 26	28,059	37,233	36,583	33,958

Table E.8 – Stochastic Risk Results by CO_2 Tax Level, Sensitivity Portfolios

	CO_2 tax level: $0/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Coal Plant Utilization Sensitivity Cases				
Case 21	1,939	23,579	29,863	30,802
Case 22	1,907	24,013	30,189	31,112
Case 23	2,269	24,106	31,624	32,514
Case 24	2,222	24,571	31,968	32,801
Load Forecast Sensitivity Cases				
Case 25	1,450	22,694	27,296	28,137
Case 26	2,284	24,621	32,049	33,059

	CO_2 tax level: $12/ton (low to very high) Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Coal Plant Utilization Sensitivity Cases				
Case 21	3,542	30,099	40,691	41,664
Case 22	3,500	30,536	41,013	41,925
Case 23	3,876	30,344	42,058	43,169
Case 24	3,825	30,815	42,396	43,437
Load Forecast Sensitivity Cases				
Case 25	2,966	29,066	37,655	38,642
Case 26	3,935	31,400	43,150	44,340

	CO_2 tax level: $19/ton Million Dollars (2011$)			
Case	**Production cost standard deviation**	**5th percentile**	**95th percentile**	**Upper-tail mean**
Coal Plant Utilization Sensitivity Cases				
Case 21	3,111	30,015	39,303	40,396
Case 22	3,072	30,448	39,594	40,692
Case 23	3,416	30,404	40,850	41,859
Case 24	3,368	30,412	40,641	41,696
Load Forecast Sensitivity Cases				
Case 25	2,534	30,003	37,280	38,432
Case 26	3,528	31,223	41,953	43,046

Portfolio PVRR Cost Component Comparison

Tables E.9 and E.10 show the breakdown of each portfolio's stochastic mean PVRR by variable and fixed cost components. These costs reflect the $19/0ton CO_2 cost adder scenario. Table E.11 reports the cost component breakdown for the core case portfolios, and table E.12 reports the cost component breakdown for the sensitivity cases.

Core Case Portfolios

Table E.9 – Core Cases 1 through 8, Portfolio PVRR Cost Components ($19 CO_2 Tax Level)

Cost Component ($ 000,000)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Variable Costs								
Fuel & O&M	15,710	15,853	15,729	16,006	15,832	15,755	15,668	15,945
Emission Cost	7,473	7,531	7,424	7,338	7,307	7,245	7,431	7,353
FOT's & Long Term Contracts	4,087	4,060	3,956	3,788	3,753	3,793	4,014	3,867
Demand Side Management	3,682	3,746	3,670	3,957	3,836	3,687	3,735	4,112
Renewables	843	696	848	848	827	787	848	870
System Balancing Sales	(5,986)	(5,923)	(5,937)	(5,987)	(5,918)	(5,963)	(5,975)	(6,015)
System Balancing Purchases	3,173	3,225	3,168	3,081	3,119	3,085	3,170	3,091
Nuclear	-	-	-	-	-	-	-	-
Energy Not Served	139	140	137	132	130	130	136	139
Dump Power	(117)	(116)	(117)	(117)	(115)	(115)	(117)	(117)
Reserve Deficiency	2	4	2	1	0	0	1	2
Total Variable Costs	**29,004**	**29,214**	**28,882**	**29,046**	**28,771**	**28,405**	**28,911**	**29,247**
Capital and Fixed Costs	5,887	5,554	5,954	6,093	6,316	6,619	5,956	6,024
Total PVRR	**34,892**	**34,768**	**34,835**	**35,139**	**35,087**	**35,024**	**34,868**	**35,271**

Table E.10 – Core Cases 9 through 16, Portfolio PVRR Cost Components ($19 CO_2 Tax Level)

Cost Component ($ 000,000)	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16
Variable Costs								
Fuel & O&M	15,884	15,046	15,180	14,812	14,724	14,765	16,130	15,710
Emission Cost	7,329	7,100	7,284	6,953	6,968	7,009	7,734	7,179
FOT's & Long Term Contracts	3,855	3,932	3,997	3,957	3,913	3,998	3,961	3,882
Demand Side Management	4,033	4,553	4,516	4,414	4,534	4,630	3,676	3,830
Renewables	866	1,298	1,328	1,379	1,328	1,315	843	870
System Balancing Sales	(6,040)	(6,120)	(6,166)	(6,315)	(6,256)	(6,330)	(6,353)	(5,798)
System Balancing Purchases	3,067	2,975	2,954	2,801	2,845	2,831	2,730	3,333
Nuclear	-	-	-	-	88	-	-	-
Energy Not Served	131	133	138	131	130	133	133	130
Dump Power	(116)	(118)	(117)	(120)	(117)	(119)	(116)	(116)
Reserve Deficiency	0	1	4	3	2	2	0	0
Total Variable Costs	**29,009**	**28,800**	**29,118**	**28,015**	**28,157**	**28,233**	**28,738**	**29,021**
Capital and Fixed Costs	6,222	7,562	7,036	8,664	8,631	8,464	6,232	6,307
Total PVRR	**35,231**	**36,362**	**36,154**	**36,678**	**36,789**	**36,698**	**34,969**	**35,327**

Table E.11 – Core Cases 17 through 19, Portfolio PVRR Cost Components ($19 CO_2 Tax Level)

Cost Component ($ 000,000)	Case 17	Case 18	Case 19
Variable Costs			
Fuel & O&M	13,909	15,239	15,446
Emission Cost	6,112	6,524	7,246
FOT's & Long Term Contracts	4,001	3,639	4,054
Demand Side Management	4,535	3,939	4,808
Renewables	1,363	843	668
System Balancing Sales	(5,586)	(5,197)	(6,093)
System Balancing Purchases	3,545	3,941	3,070
Nuclear	44	-	-
Energy Not Served	131	128	137
Dump Power	(119)	(114)	(115)
Reserve Deficiency	2	0	1
Total Variable Costs	**27,937**	**28,942**	**29,221**
Capital and Fixed Costs	10,099	6,849	6,907
Total PVRR	**38,036**	**35,790**	**36,128**

Table E.12 – Coal Plant Utilization Sensitivity and Load Forecast Scenario ($19 CO_2 Tax Level)

Cost Component ($000,000)	Coal	Coal	Coal	Coal	Low Economic Growth	High Economic Growth
Description	**Case 21**	**Case 22**	**Case 23**	**Case 24**	**Case 25**	**Case 26**
Variable Costs						
Fuel & O&M	15,653	15,594	15,822	15,773	14,954	16,599
Emission Cost	7,420	7,409	7,226	7,227	7,199	7,656
FOT's & Long Term Contracts	4,054	4,043	4,048	4,032	3,981	3,954
Demand Side Management	3,675	4,117	3,991	4,003	3,920	3,817
Renewables	848	871	847	873	832	851
System Balancing Sales	(5,958)	(5,962)	(5,983)	(5,983)	(6,142)	(5,940)
System Balancing Purchases	3,156	3,145	3,123	3,116	2,978	3,235
Nuclear	-	-	-	-	-	-
Energy Not Served	148	147	145	119	111	166
Dump Power	(116)	(116)	(116)	(116)	(119)	(113)
Reserve Deficiency	2	1	1	1	1	2
Total Variable Costs	**28,881**	**29,249**	**29,103**	**29,046**	**27,715**	**30,228**
Capital and Fixed Costs	5,976	5,992	6,458	6,458	6,356	6,356
Total PVRR	**34,857**	**35,241**	**35,561**	**35,504**	**34,071**	**36,583**

Table E.13 – Coal Plant Utilization Sensitivity and Load Forecast Scenario ($0 CO_2 Tax Level)

Cost Component ($000,000)	Coal	Coal	Coal	Coal	Low Economic Growth	High Economic Growth
Description	**Case 21**	**Case 22**	**Case 23**	**Case 24**	**Case 25**	**Case 26**
Variable Costs						
Fuel & O&M	15,765	15,721	15,879	15,849	15,139	16,798
Emission Cost	2	2	2	2	2	2
FOT's & Long Term Contracts	3,848	3,839	3,843	3,831	3,792	3,770
Demand Side Management	3,675	4,117	3,991	4,003	3,920	3,817
Renewables	788	803	789	807	777	818
System Balancing Sales	(5,572)	(5,577)	(5,574)	(5,577)	(5,769)	(5,754)
System Balancing Purchases	2,134	2,126	2,137	2,128	1,964	2,191
Nuclear	-	-	-	-	-	-
Energy Not Served	149	148	147	145	112	173
Dump Power	(120)	(120)	(120)	(120)	(122)	(114)
Reserve Deficiency	2	1	1	1	1	2
Total Variable Costs	**20,672**	**21,061**	**21,095**	**21,069**	**19,815**	**21,704**
Capital and Fixed Costs	5,976	5,992	6,458	6,907	5,327	6,356
Total PVRR	**26,648**	**27,053**	**27,553**	**27,976**	**25,142**	**28,059**

Table E.14 – Coal Plant Utilization Sensitivity and Load Forecast Scenario ($12 CO_2 Tax Level)

Cost Component ($000,000)	Coal	Coal	Coal	Coal	Low Economic Growth	High Economic Growth
Description	**Case 21**	**Case 22**	**Case 23**	**Case 24**	**Case 25**	**Case 26**
Variable Costs						
Fuel & O&M	14,111	14,050	14,324	14,280	13,484	15,013
Emission Cost	7,309	7,299	6,950	6,957	7,104	7,610
FOT's & Long Term Contracts	3,813	3,805	3,809	3,793	3,745	3,723
Demand Side Management	3,675	4,117	3,991	4,003	3,920	3,817
Renewables	847	870	847	873	830	845
System Balancing Sales	(4,126)	(4,133)	(4,152)	(4,159)	(4,319)	(4,112)
System Balancing Purchases	3,852	3,840	3,818	3,811	3,619	3,920
Nuclear	-	-	-	-	-	-
Energy Not Served	153	152	150	148	117	171
Dump Power	(116)	(116)	(116)	(116)	(118)	(112)
Reserve Deficiency	2	1	1	1	1	2
Total Variable Costs	**29,519**	**29,886**	**29,621**	**29,592**	**28,383**	**30,877**
Capital and Fixed Costs	5,976	5,992	6,458	6,907	5,327	6,356
Total PVRR	**35,495**	**35,877**	**36,079**	**36,499**	**33,710**	**37,233**

APPENDIX F – THE PUBLIC INPUT PROCESS

A critical element of this resource plan is the public input process. PacifiCorp has pursued an open and collaborative approach involving the Commissions, customers and other stakeholders in PacifiCorp's planning process prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the resource plan with transparency and full participation from Commissions and other interested and affected parties is essential.

The public has been involved in this resource plan from its earliest stages and at each decisive step. Participants have both shared comments and ideas and received information. As reflected in the report, many of the comments provided by the participants have been adopted by PacifiCorp and have contributed to the quality of this resource plan. PacifiCorp will adopt further comments going forward, either as elements of the Action Plan or as future refinements to the planning methodology.

The cornerstone of the public input process has been full-day public input meetings held approximately throughout the year-long plan development period. These meetings have been held jointly in two locations—Salt Lake City, Utah and Portland Oregon—using telephone and video conferencing technology.

IRP public process continued with state stakeholder dialogue sessions from mid-June through August 2010. These goal of these sessions, targeting a state-specific audience, were to (1) capture key resource planning issues of most concern to each state, and discuss how these can be tackled from a system planning perspective, (2) ensure that stakeholders understand PacifiCorp's planning principles and the logic behind its planning process, and (3) set expectations for what can be accomplished in the current IRP/business planning cycle. These State focused 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 general public meetings.

As far as agenda setting is concerned, PacifiCorp solicited recommendations from the state stakeholders in advance of the session, as well as allowing open time to ensure that participants had adequate time for dialogue. Some follow-up activities arising from the sessions were addressed in subsequent public meetings.

The 2010 public input meetings were augmented by a series of focused technical workshops to provide an opportunity to discuss complex topics for a multi-state utility in more detail.

Participant List

Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission

- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Intervenors

- Attorney General of Washington
- Brigham Young University
- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- ECOS Consulting
- Encana Corporation
- enXco
- Energy Trust of Oregon
- Energy Strategies, LLC
- HEAL Utah and Utah Physicians for a Healthy Environment
- Health Environment Alliance of Utah (HEAL)
- Horizon Wind Energy
- Iberdrola
- Industrial Customers of Northwest Utilities
- Interwest Energy Alliance
- Kennecott
- Mountain West Consulting, LLC
- Northwest Power and Conservation Council
- Northwest Pipeline GP
- NW Energy Coalition
- Oregon Department of Energy
- Powder River Basin Resource Council
- Renewables Northwest Project
- Salt Lake City
- Salt Lake Community Action Program
- Southwest Energy Efficiency Project
- Sierra Club , Utah Chapter
- U.S. Department of Energy - Intermountain Clean Energy Application Center
- U.S. Department of Energy - Northwest Clean Energy Application Center
- Utah Association of Energy Users
- Utah Clean Energy Alliance
- Utah Division of Air Quality
- Utah Division of Public Utilities
- Utah Energy Office
- Utah Geological Survey
- Wasatch Clean Air Coalition
- Western Resource Advocates
- West Wind Wires
- Wyoming Industrial Energy Consumers

- Wyoming Office Of Consumer Advocacy

Others

- Avista Utilities
- Cadmus Group Inc.
- GDS Associates
- Idaho Power Company
- John Klingele (Washington Customer)
- Portland General Electric (PGE)

PacifiCorp extends its gratitude for the time and energy these participants have given to the resource plan. Your participation has contributed significantly to the quality of this plan, and your continued participation will help as PacifiCorp strives to improve its planning efforts going forward.

Public Input Meetings

PacifiCorp hosted five full-day public input meetings, two half day meetings, one conference call and six state meetings during the 2010. During the 2011 IRP process presentations and discussions covered various issues including inputs and assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings and the technical workshops.

General Meetings

April 28, 2010

- IRP Group and Support Team
- Discussion on the wind integration study methodology white paper
- IRP Regulatory Compliance (2008 IRP / 2011 IRP)
- IRP Preparation Schedule and Public Process
- IRP Modeling Plan and Initiatives
- 2008 IRP Update

August 4, 2010

- Demand-side management / distributed generation
- Supply-side Resources
- Planning Reserve Margin (PRM) analysis
- Proposed portfolio development cases

October 5, 2010

- IRP Schedule Update
- Energy Gateway Transmission Construction Update and Evaluation
- Load Forecast
- Hedging Strategy
- Market Reliance Analysis
- Capacity Load & Resource Balance
- Portfolio Development Cases

December 15, 2010

- Planning Reserve Margin and LOLP
- Update on Assumptions
  - Load Forecast Scenarios
  - DSM Supply Curves
- Update Load and Resource Balance
- Preliminary Results for Core Cases and Transmission

January 27, 2011

- Solar photovoltaic resource modeling

January 31, 2011

- Review of System Optimizer Core Case Results – Cases 1 to 19

February 23, 2011

- Stochastic production cost modeling results
- preferred portfolio selection
- coal utilization study results

March 23, 2011

- Preferred portfolio discussion,
- Remaining portfolio sensitivity results, and
- the IRP action plan

State Meetings

June 16, 2010 – Oregon / California

- Evaluating distribution efficiency potential
- Wind integration study
- Transmission financial analysis
- Assumptions update for portfolio analysis / All-source RFP
- Intermediate-term Market Purchases
- Out-year resource selection
- Enhanced regulatory impact modeling
- Use of carbon dioxide emissions for portfolio performance scoring
- Open Discussion Items – Smart Grid and PacifiCorp Modeling

June 29, 2010 – Utah

- Renewable/non-traditional Resource Evaluation
  Wind integration study

Distributed solar
Resource modeling and characterization
Sensitivity analysis of incentive programs (e.g., level of incentive needed to make distributed solar cost-effective)
Hybrid intermittent/storage technologies
Commercial geothermal potential study

- DSM Potential Study
  Treatment of achievable potential adjustments
  Application of the Utility Cost Test
- Market Risk Assessment
  Price hedging strategy
  Inclusion of hedging costs in portfolio resources
  Sensitivity analysis of hedging strategies to minimize costs and risks for customers
  Market purchase risk assessment
  WECC Power Supply Assessment
  Stochastic simulation and risk analysis
- Resource Adequacy
  Planning reserve margin evaluation
  Sensitivity analysis of Energy Not Served (ENS) price; i.e., flat vs. tiered approach
  Hydro sustained peaking capability
  Treatment of planned resources
- Load Forecasting
  GDS Consulting recommendations for the 2008 IRP
  Load forecast scenarios
  Standalone load forecast report
  Stochastic parameter estimation
- Model Training

July 28, 2010 – Idaho

- 2008 IRP Acknowledgement Letter
- Discount rate impact on resource timing and selection
- Wind integration costs – justification and stochastic modeling support
- Quantifying Renewable Portfolio Standard costs and other jurisdictional mandates
- Portfolio selection process and weighting scheme

August 11, 2010 – Wyoming

- ENS in Portfolio Modeling
- Planning Reserve Margin
- CO2 Modeling: Tax versus Cap-n-Trade
- Supply-side Option Table
- LOLP
- Weighting Schemes

Parking Lot Issues

During the course of the public input meetings, certain concerns or questions needed additional follow-up from PacifiCorp. These questions or issues were taken off-line and addressed in a meeting report or at a subsequent public input meeting or workshop.

Public Review of IRP Draft Document

PacifiCorp distributed the draft document materials on February 23 and March 7, 2011 for public review. Public comments were requested by March 24, 2011. Parties that submitted comments include:

- Encana Corporation
- HEAL Utah and Utah Physicians for a Healthy Environment
- Interwest Energy Alliance
- Powder River Basin Resource Council
- Renewable Northwest Project
- Sierra Club
- Utah Association of Energy Users
- Utah Clean Energy
- Utah Public Service Commission Staff
- U.S. Department of Energy - Northwest Clean Energy Application Center
- U.S. Department of Energy - Intermountain Clean Energy Application Center
- Washington Utility and Transportation Commission
- Western Resource Advocates

Many of the clarifications and information requested through the written comments, verbal suggestions from the March 23, 2011 conference call, and data requests, have been incorporated into the final version of the IRP.

Contact Information

PacifiCorp's IRP internet website contains many of the documents and presentations that support recent Integrated Resource Plans. To access it, please visit the company's website at http://www.PacifiCorp.com click on the menu "Energy Sources" and select "Integrated Resource Planning".

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

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

Electronic Email Address:
IRP@PacifiCorp.com

Phone Number:
(503) 813-5245

APPENDIX G – HEDGING STRATEGY

Introduction

This appendix addresses two Public Service Commission of Utah analysis requirements pertaining to price hedging.

- "At a minimum, we direct the Company to include the costs of hedging in its IRP analysis of resources that rely on fuels subject to volatile prices."
- "We also direct the Company to perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers."[3]

To address these requirements, this appendix presents a comparison among hedging strategies to demonstrate that while the expected value of all hedging strategies is the same, different strategies have differing risk profiles. The consequence is that selection of a hedging strategy is made not by expected outcome but by risk tolerance, and that hedging outcomes net to a zero expected value on a long-term basis.

Hedging

Purpose of Hedging

Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market price changes. The Company has exposure to power and natural gas wholesale market price changes due to its responsibility to serve retail load and to economically dispatch its resources. The Company cannot avoid such exposure but can reduce it through hedging. A long forward power position occurs when the amount of energy anticipated to be economically produced by the Company's resources exceeds the amount of energy forecast to be consumed by retail customers, and the Company risks financial loss if wholesale power market prices fall. A short forward natural gas position occurs when the Company's natural gas generation is expected to economically convert natural gas to power and the Company risks financial loss if wholesale natural gas market prices rise. The Company may also have short power positions and, at times, long natural gas positions. All of these open positions result in price risk.

Need for Hedging

Perfect foresight of future wholesale market prices is unattainable by any hedging entity, including the Company. While the Company may have a view of where it believes prices are heading – up, down, or no change – it does not have the ability to predict without error such price changes. The Company has incentive to protect against unfavorable wholesale market

[3] Public Service Commission of Utah, "In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan", Report and Order, Docket No 09-2035-01, April 1, 2009, p. 30.

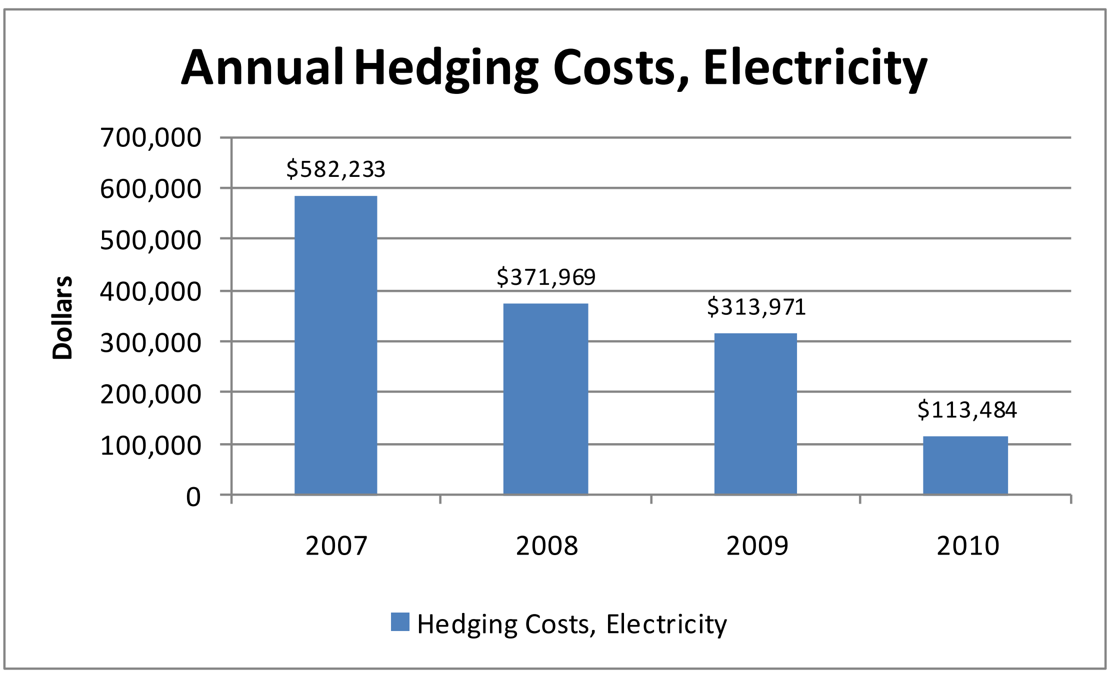
price changes and does so by hedging to reduce the range of net power cost outcomes for any wholesale market price changes.

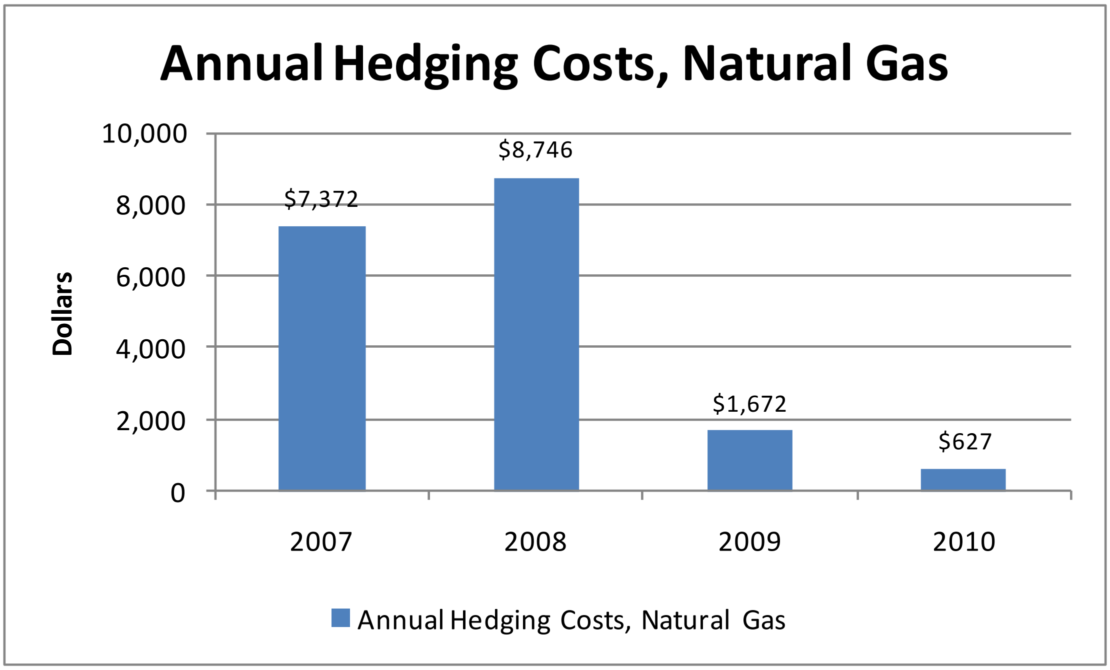
Impact of Hedging and Hedging Costs

Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. Increased hedging reduces both the potential losses and potential gains. Therefore, if the Company has a low risk tolerance it would hedge a greater amount than if it has a high risk tolerance. *Hedging does not, however, modify the expected outcome of net power costs associated with wholesale market price changes.* Any hedging program, whether it utilizes fixed-price forward or option products, would result in the same expected net power costs from the perspective of the time the hedges are transacted. Historical gains and losses due to hedging are only indicative of potential opportunity costs for having pursued an alternate hedging strategy once the outcome is already known.

With respect to hedging costs, which the Company defines as hedging program expenses, Figure G.1 shows the trend in the Company's annual costs for both electricity and natural gas hedging activities (broker fees). As can be seen, the hedging costs are too small to be used as a meaningful distinguishing factor among resources and portfolios.

Figure G.1 – PacifiCorp's Annual Electricity and Natural Gas Hedging Costs





Hedge Products

The basic hedge products available to the company are fixed-price forwards and, to a lesser extent, vanilla options. All basic hedging strategies are in theory implementable using combinations of these two types of products. In practice, however, the Company almost exclusively employs fixed-priced forwards. This is because forward markets relevant to the Company are liquid, and the costs have been determined to be recoverable.

In contrast, options have a number of disadvantages to the Company. There are not liquid regional options markets, meaning that any options available have a high additional cost reflected in the spread between the buyer's bid price and the seller's ask price. There is an active natural gas options market at Henry Hub, but the price of natural gas in the Company's region does not necessarily move in lock-step with the price of natural gas at Henry Hub. This is known as basis risk, and is undesirable. Finally, because options require payment up-front for benefits that may or may not occur in the future, it is not clear that the Company would be able to recover the cost of unexercised options in rates.

No "Best" Hedging Strategy

Among the myriad conceivable hedging strategies there is no purely objective optimization method resulting in the best strategy. Determining a strategy that is best for the Company is necessarily in part a subject evaluation. Parameters that must be considered are market liquidity, types and availability of desired hedge products, customer risk tolerance, and cost of hedge program management, to name a few.

Sample Portfolio Simulations

Various hedging programs have been simulated to demonstrate the impact to the range of net power cost outcomes and to demonstrate there is no change to the expected outcome. The measurement of range of net power cost outcomes is the "to-expiry value-at-risk" distribution. This TEVaR distribution is a statistically-generated distribution of outcomes that is wider or narrower based upon the aggregate volatility of the combined power and natural gas portfolio. Inasmuch as being short natural gas naturally offsets being long power, one would expect the TEVaR distribution of a long-power/short-natural gas portfolio to be significantly narrower than the distribution of either individual component.

Five portfolios were simulated using Monte Carlo technique to calculate to-expiry value-at-risk. The first portfolio, entitled "Reference portfolio," is comprised of a 500 average MW power long position and a (100,000) MMBtu/day natural gas short position. This represents the Company's hypothetical combination of retail load, economic generation and transactions that partially hedge the position. The long power and short natural gas positions are largely offsetting. This is used as the reference portfolio for the following scenario analyses.

The second portfolio, entitled "less hedged," is comprised of 625 average MW power long position and (125,000) MMBtu/day natural gas short position. Relative to the reference portfolio, this demonstrates the change in risk profile of a portfolio with 25% less hedged position. In this portfolio, there are 125 average MW fewer hedge transactions resulting in more power length, and 25,000 MMBtu/day fewer hedge transactions resulting in a shorter natural gas short position.

The third portfolio, entitled "more hedged," is comprised of 375 average MW power long position and (75,000) MMBtu/day natural gas short position. Relative to the reference portfolio, this demonstrates the change in risk profile of a portfolio with 25% more hedged position. In this portfolio, there are 125 average MW more hedge transactions resulting in less power length and 25,000 MMBtu/day more hedge transactions resulting in less short natural gas position.

The fourth portfolio, entitled "Hedge only power," is comprised of a fully hedged power position and (100,000) MMBtu/day natural gas short position. Relative to the reference portfolio, this demonstrates hedging all power but no natural gas.

The fifth portfolio, entitled "Hedge only natural gas," is comprised of a 500 average MW power long position and a fully hedged natural gas position. Relative to the reference portfolio, this demonstrates hedging all natural gas but no power.

Results

Charts of the results are shown below (Figures G.2 through G.5). In addition, for ease of comparison among portfolios, Table G.1 below shows the expected value, the fifth percentile outcome (very unfavorable prices), and the 95th percentile outcome (very favorable prices). These values shown are relative, so that $0 expected value indicates the potential change in portfolio value due to market price changes is expected to be neutral. This is the statistical equivalent of the earlier assertion that hedging can only reduce the range of potential net power costs, but cannot reduce expected net power costs. .

The reference portfolio, shown in blue in each of the four charts, has an unsymmetrical fifth and 95th percentile result due to the likelihood that prices may increase more than decrease, and due to the reference portfolio being net short. A log-normal price distribution is used to represent this effect.

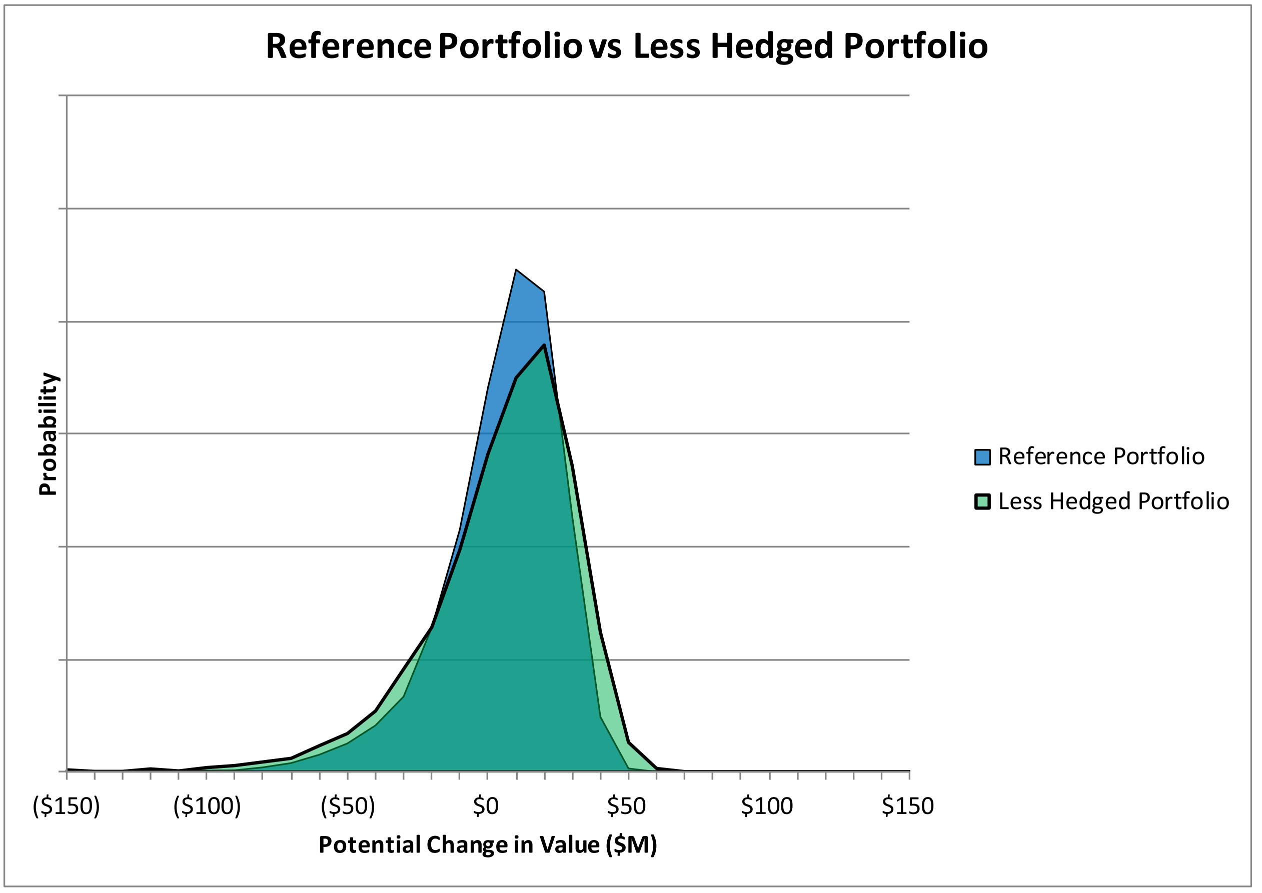
In the less hedged sample portfolio, both the power and natural gas volumes are 25 percent larger than the reference portfolio. Conversely in the more hedged sample portfolio, both the power and natural gas volumes are 25 percent smaller than the reference portfolio. As expected, the less hedged portfolio shows a wider distribution of outcomes representing a higher risk to price changes. Similarly, the more hedged portfolio shows a narrower distribution.

The "hedge only power" portfolio shows a much wider distribution due to the severe reduction in the natural offset between power and natural gas in the reference portfolio. The "hedge only natural gas" has a similar distribution. Of note is the 5th percentile "hedge only power" portfolio is much greater downside than the "hedge only natural gas" portfolio, and this is due to the log-normal prices.

Table G.1 – Comparison of Multiple Sample Portfolios

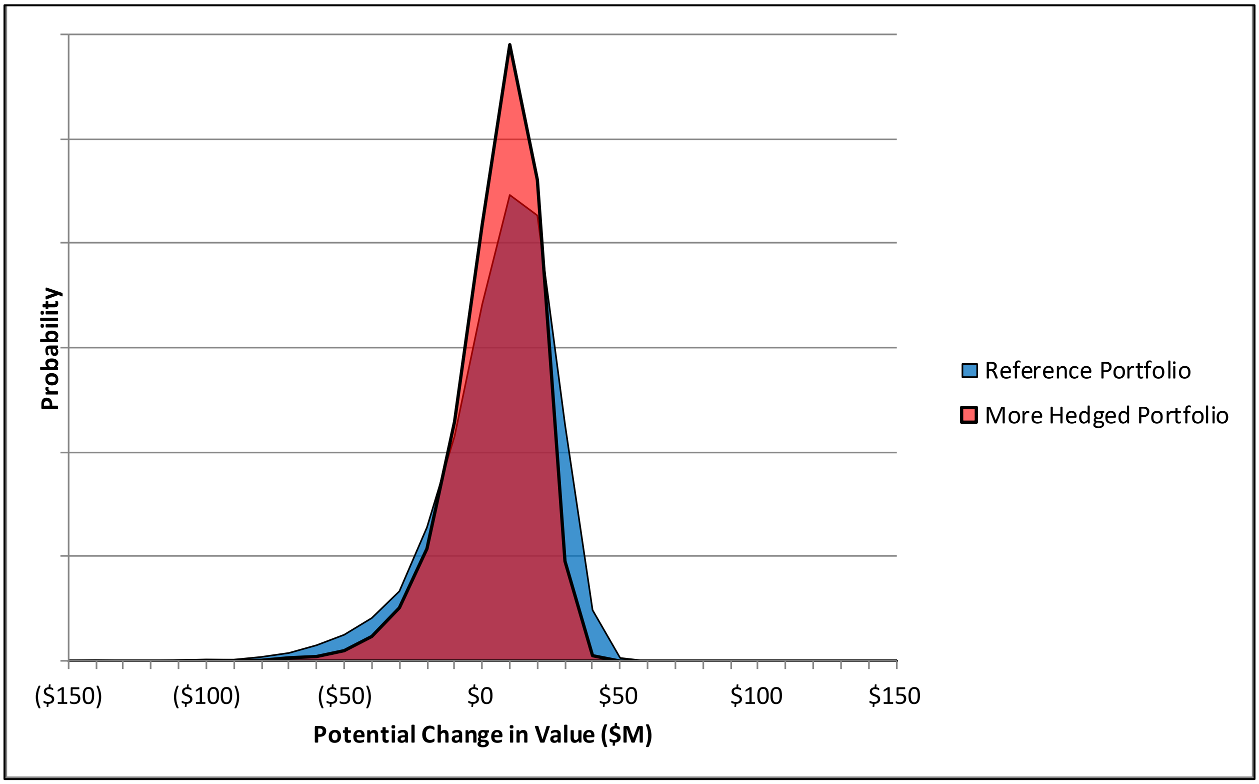
Portfolio Simulation (open hedged positions)	5th Percentile (million $)	Expected Value (million $)	95th Percentile (million $)
Reference portfolio 500 average MW power (100,000) MMBtu/day natural gas	($40)	$0	$27
Less hedged 625 average MW power (125,000) MMBtu/day natural gas	($48)	$0	$33
More hedged 375 average MW power (75,000) MMBtu/day natural gas	($29)	$0	$20
Hedge only power 0 average MW power (100,000) MMBtu/day natural gas	($92)	$0	$66
Hedge only natural gas 500 average MW power 0 MMBtu/day natural gas	($48)	$0	$62

Figure G.2 – Reference Portfolio versus Less Hedged Portfolio



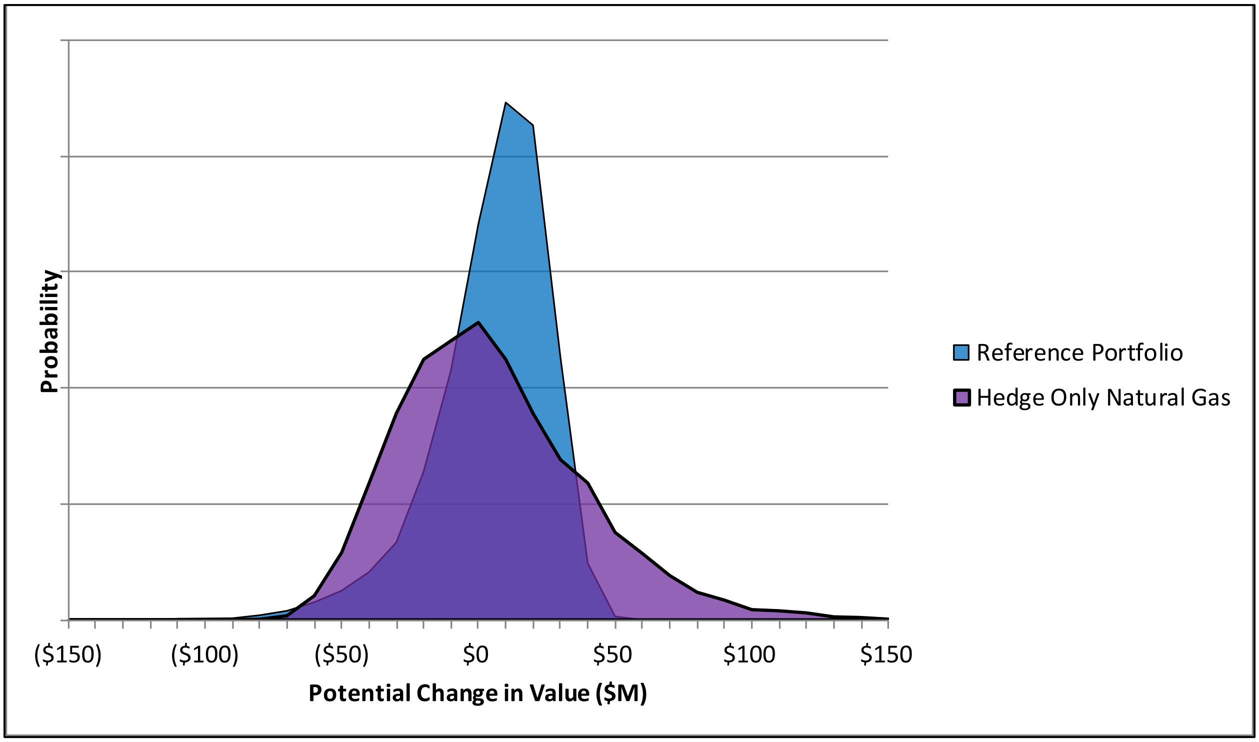
In the "Reference Portfolio versus Less Hedged Portfolio" chart, the less hedged portfolio has a wider distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the less hedged portfolio will return a wider range of outcomes.

Figure G.3 – Reference Portfolio versus More Hedged Portfolio



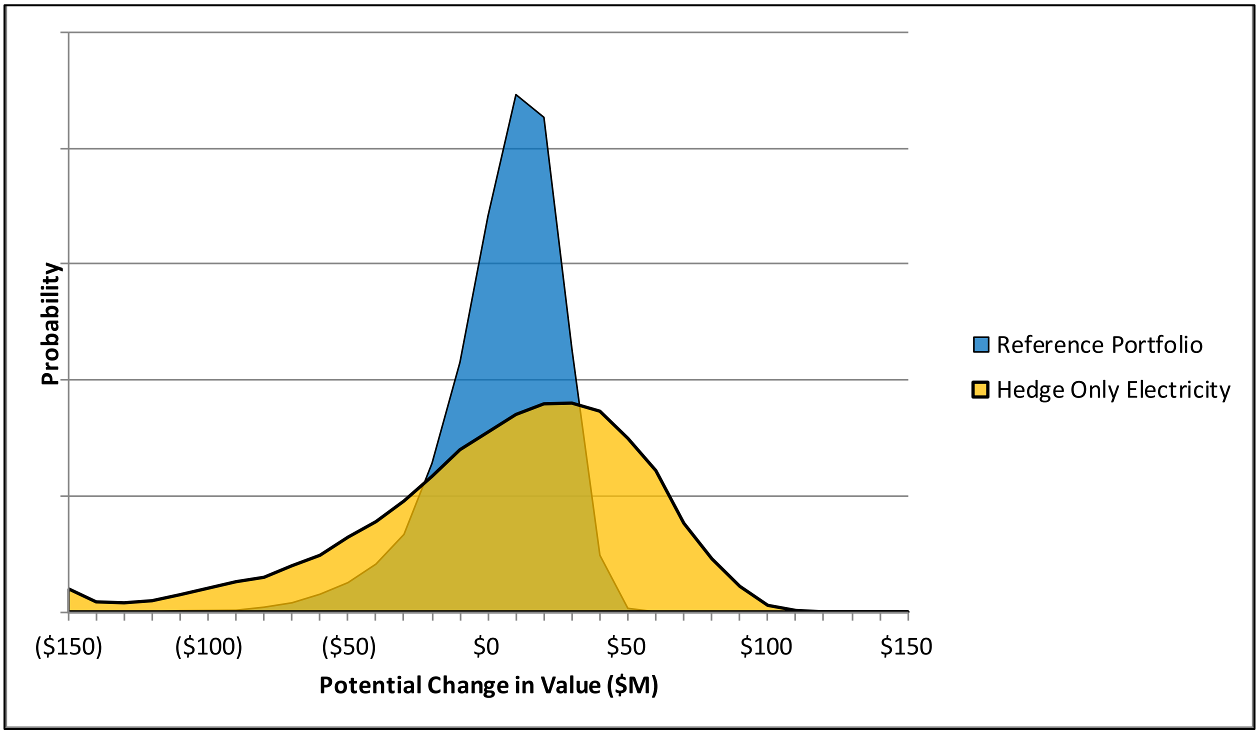
In the "Reference Portfolio versus More Hedged Portfolio", the more hedged portfolio has a tighter distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the more hedged portfolio will return a tighter range of outcomes.

Figure G.4 – Reference Portfolio versus Hedging Only Natural Gas



In the "Reference Portfolio versus Hedging Only Natural Gas", the portfolio where only natural gas has been hedged (and electricity positions left unhedged) has a significantly wider distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the alternate portfolio will return a significantly wider range of outcomes. This is due to removing the natural offsetting features of one commodity (i.e., hedging the short natural gas position) while leaving the long electricity position unhedged.

Figure G.5 – Reference Portfolio versus Hedging Only Electricity



In the "Reference Portfolio versus Hedging Only Electricity", the portfolio where only electricity has been hedged (and natural gas positions left unhedged) has a significantly wider distribution of results than the reference portfolio. While both portfolios have an expected value of zero over all potential scenarios, the alternate portfolio will return a significantly wider range of outcomes. This is due to removing the natural offsetting features of one commodity (i.e., hedging the long electricity position) while leaving the short natural gas position unhedged.

Conclusion

Hedging does not modify the expected outcome of net power costs associated with wholesale market price and natural gas price changes. Consequently, the long-term gains and losses from hedging are expected to net to zero. As shown in Figure G.1 above, the Company's hedging costs are not material enough to warrant adjustment to resource costs or influence portfolio selection.

In regard to assessment of hedging strategies, a hedging strategy should be tailored to fall within a designated risk tolerance and conform to Company financial and administrative capabilities. A rationale must be created taking into account risk tolerance for adverse impacts to net power costs, and effects including market liquidity and hedge product availability, credit risk, and costs such as collateral funding for margining,

Finally, PacifiCorp shows that there is no objective measurement to indicate the optimum amount of hedging, as demonstrated by a sensitivity analysis that compares a reference portfolio, a less hedged portfolio, and a more hedged portfolio. Nevertheless, the analysis shows that hedging should take full advantage of any natural offsets between long power and short natural gas positions. Not taking advantage results in high risk (a wider distribution of outcomes) as indicated in the “hedge only power” and “hedge only natural gas” portfolios.

APPENDIX H – WESTERN RESOURCE ADEQUACY EVALUATION

Introduction

The Utah Commission, in its 2008 IRP acknowledgment order, directed the Company to conduct two analyses pertaining to the Company's ability to support reliance on market purchases:

> *Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.*[4]

To fulfill the first requirement, PacifiCorp evaluated the Western Electricity Coordinating Council (WECC) Power Supply Assessment reports to glean trends and conclusions from the supporting analysis. This evaluation, along with a discussion on risk allocation associated with reliance on market purchases, is provided below. As part of this evaluation, the Company also reviewed the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

Finally, this appendix describes a study that involved the development and stochastic simulation of a market "stress" scenario. In developing this study, the Company received input from participants at the June 29, 2010 Utah IRP stakeholder's meeting, and described its proposed study approach at the October 5, 2010, IRP general public input meeting. This appendix describes the study methodology and presents results of the stochastic simulations.

Western Electricity Coordinating Council Resource Adequacy Assessment

The Western Electricity Coordinating Council (WECC) 2010 Power Supply Assessment (PSA) shows WECC needing additional resources in 2019. Resource need is identified when load (including a target reserve margin) exceeds available resources[5]. Since 2006, each subsequent PSA study defers resource need to later years. This deferment is a function of net changes to: load growth expectations, class I capacity entrants, scheduled retirements, resource performance, transfer capabilities and modeling convention.[6]

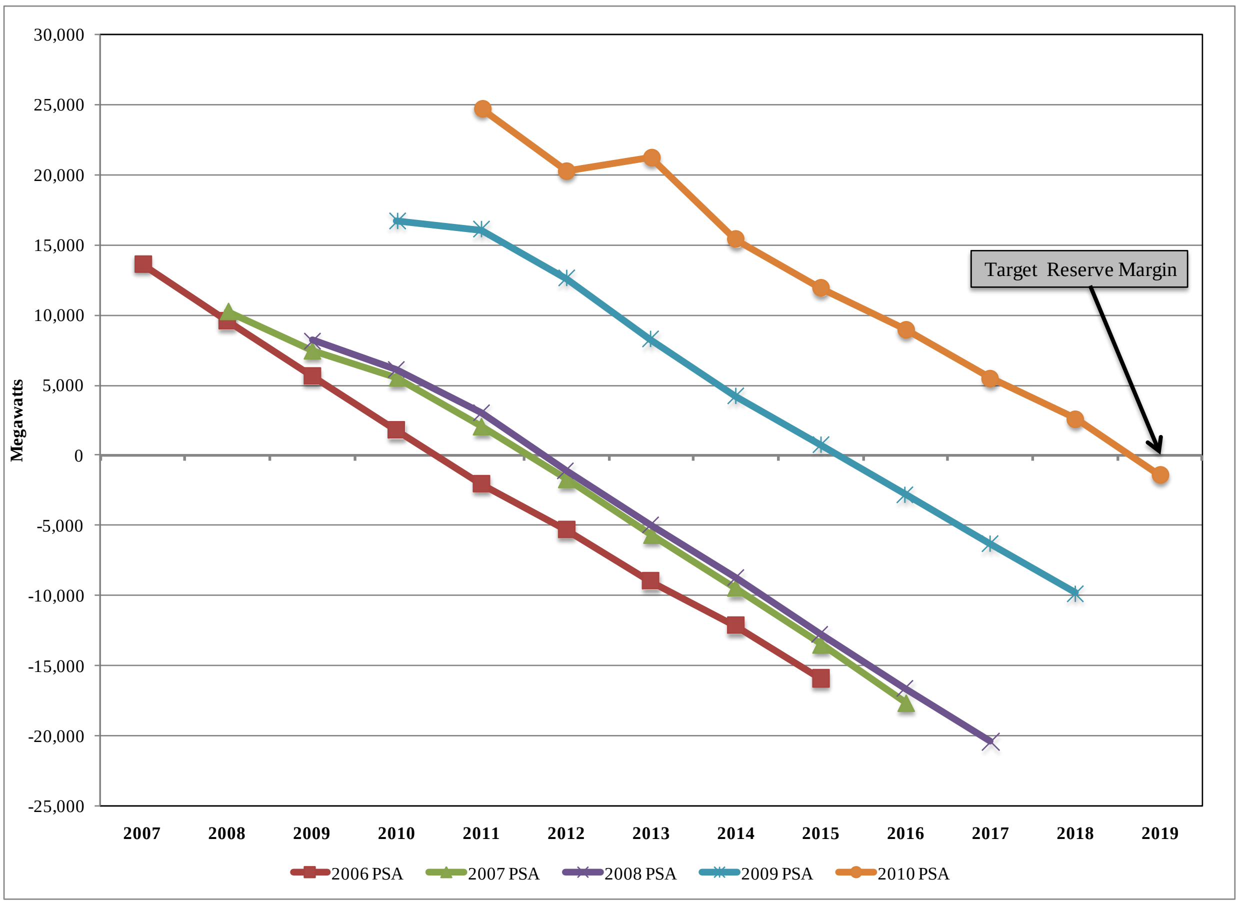
[4] Public Service Commission of Utah, PacifiCorp 2008 Integrated Resource Plan, Report and Order, Docket No. 09-2035-01, p. 30.

[5] Available resources = Existing Generation + Class I Add/Retire - Outage/Derate Adjustments + Net Imports.

[6] The 2010 PSA defines Class I capacity as being actively under construction and online before January 1, 2014. The 2009 & 2008 PSA require Class I resources to be online by January 1, 2013 and January 1, 2012, respectively.

As seen in Figure 1, there were two significant capacity deferments: from 2012 (per 2008 PSA) to 2016 (per 2009 PSA) followed by 2019 as seen in WECC's 2010 PSA. While the forecast power supply margins (PSM) of the studies from 2006 through 2009 are comparable, the 2010 PSA employed a different, and superior, modeling convention. Namely, the 2010 PSA used PROMOD IV, a chronological production cost model to assess WECC resource adequacy[7]. PROMOD IV, unlike WECC's previous model, uses coincident peak demand and employs a more robust optimization of sub-regional transfers. It is noteworthy that even the 2009 PSA, using the old modeling convention and non-coincident peak demands, did not forecast a capacity need until 2016.

Figure H.1 – WECC Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only

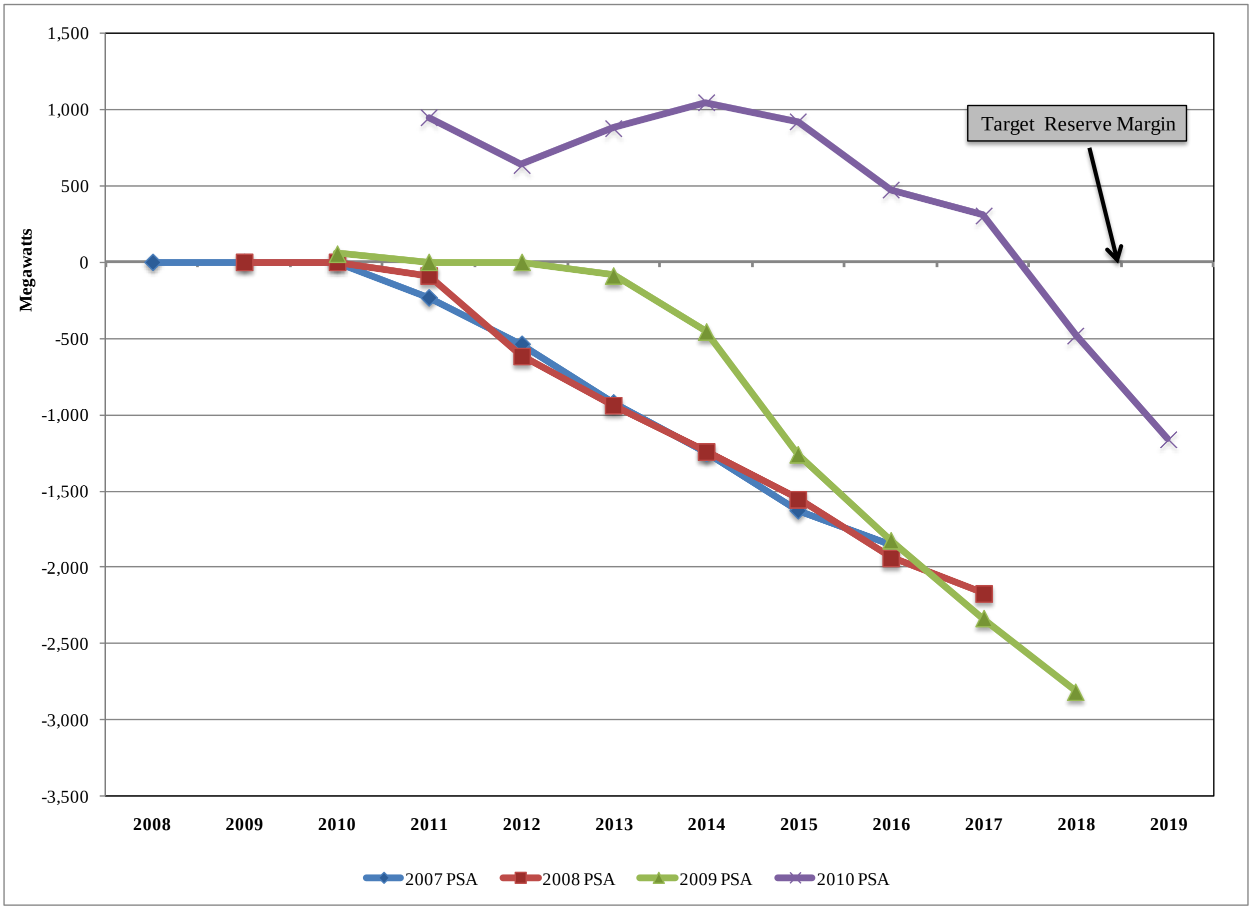
Of particular interest is Basin, a summer peaking sub-region comprised of Utah, Idaho, and northern Nevada. A review of PSA studies from 2007 through 2010 reveals a similar pattern to that of WECC.[8] The 2009 PSA identified a capacity need in 2013; the 2010 PSA defers the need until 2018. As seen in Figure 2, the target reserve margin is maintained at the "zero" horizontal axis.

[7] PROMOD IV is electricity market simulation software licensed through Ventyx, an ABB Company. http://www.ventyx.com/analytics/promod.asp

[8] Basin was not broken out as a sub-region in WECC's 2006 PSA.

The PSA's target reserve margins, as developed by WECC, are not mandated. Instead, they serve as a reasonable proxy for expected target reserve margins in WECC's modeling construct.

Figure H.2 – Basin Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only

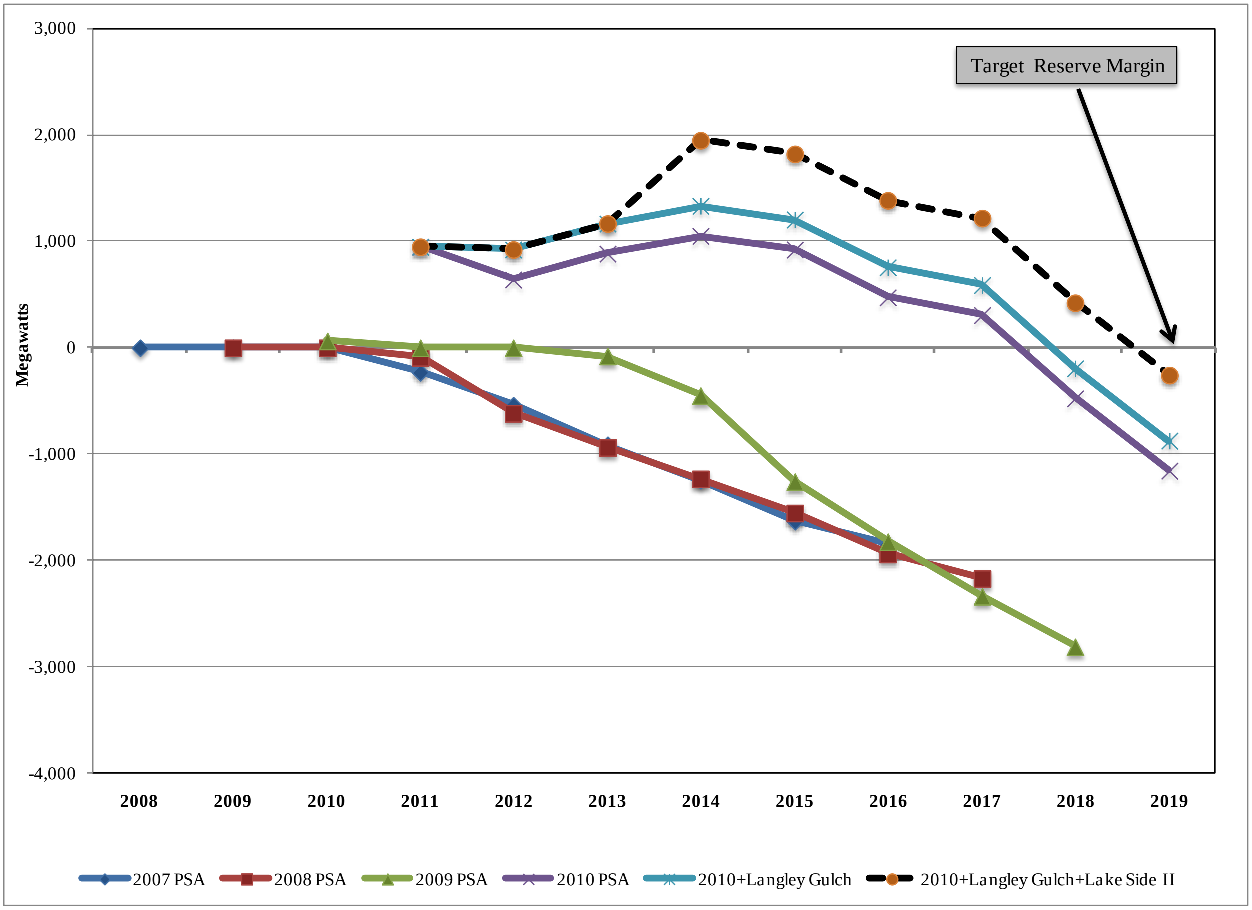
The 2010 PSA, and previous PSA versions, use a four-tier building block approach to calculating a sub-region's target reserve margin. The first block, contingency reserves, is set at 6% of a balancing authority's (BA) load. The second block, regulating reserves, is the amount of spinning reserves needed to instantly match increases in electric load. Expected regulating reserve levels were furnished by BAs to WECC in a 2010 data request. The third block covers additional forced outages beyond what is covered by operating reserves in the event of a second contingency event. The fourth block, temperature adders, is the incremental amount of reserves needed to cover a 1-in-10 temperature event. For modeling purposes, a BA's load requirement is the sum of the BA's peak demand forecast plus the WECC's four-tier target reserve margin[9].

As such, a sub-region's calculated target reserve margin should cover a second contingency event in tandem with a 1-in-10 temperature event. Moreover, with the addition of Idaho Power's

[9] A BA's peak demand forecast incorporates a 1-in-2 chance of temperature exceedance.

Langley Gulch[10] in 2012 and PacifiCorp's Lake Side 2[11] in 2014, additional capacity will not be needed until 2019 as shown in Figure H.3 (Note: Figure H.3 is a modified version of the Original PSA chart that includes the Langley Gulch and Lake Side 2 resources.)

Figure H.3 –Basin Forecasted Power Supply Margins with Selected Capacity Additions

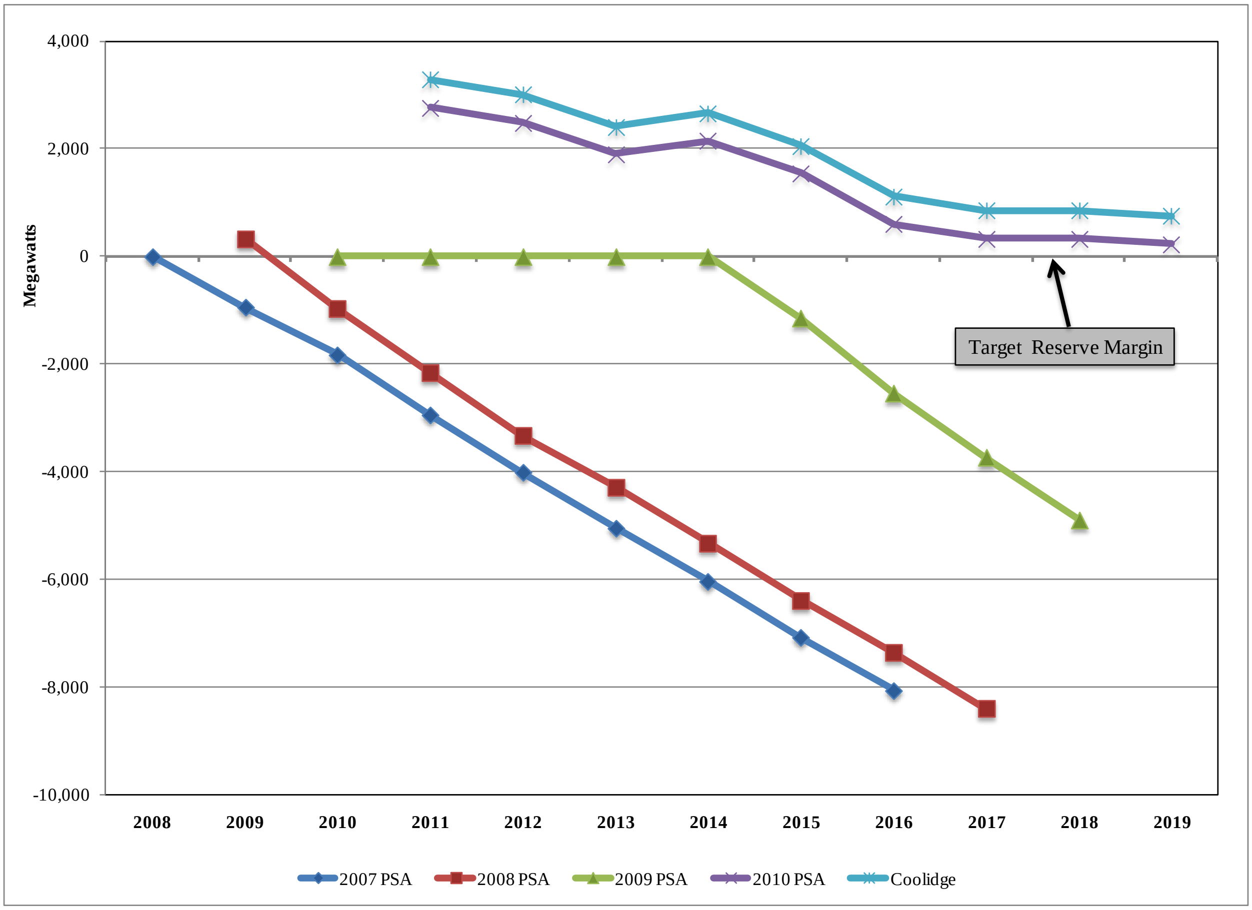


Note: WECC Power Supply Assessment includes Class 1 Planned Resources only. Langley Gulch, currently under construction, and Lake Side 2 as proposed by PacifiCorp are included here to better reflect Basin's capacity status in later years.

[10] Langley Gulch is a 280-MW summer rated combined cycle under construction in Idaho. It was not included in the 2010 PSA as a Class I entrant since it was not under construction at publishing time.
[11] PacifiCorp is seeking to acquire Lake Side 2, a 637-megawatt combined-cycle combustion turbine plant at the Lake Side site in Utah.

As seen in Figures 4 and 5, neither the Desert Southwest nor the Rockies subregions are expected to need additional capacity prior to 2020.[12]

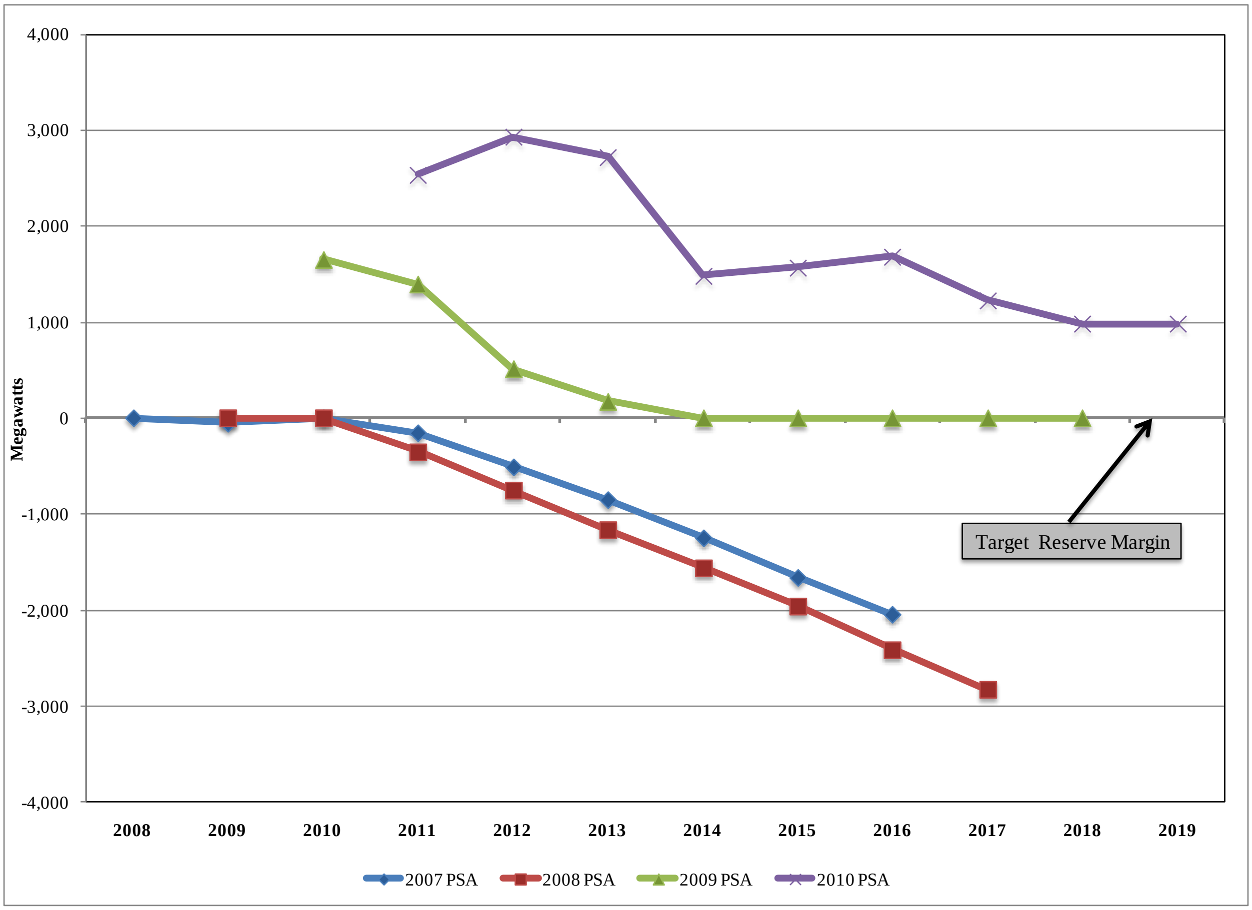
Figure H.4 – Desert Southwest Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only. Coolidge Generating is included.

[12] Coolidge Generating is 512-MW gas turbine under construction in Arizona. It was not included in the 2010 PSA as a Class I entrant since it was not under construction at publishing time.

Figure H.5 – Rockies Forecasted Power Supply Margins



Note: WECC Power Supply Assessments includes Class 1 Planned Resources Only.

Market depth refers to a market's ability to accept individual transactions without a perceptible change in market price. While different from market liquidity[13] the two are linked in that a deep market tends to be a liquid market. Market depth in electricity markets is a function of the number of economic agents, market period, generating capacity, transmission capability, transparency, and institutional and/or physical constraints. Based on the 2010 PSA, WECC maintains a positive PSM through 2018. The Desert Southwest, Northwest[14], and Rockies subregions are forecasted to maintain a positive PSM through 2019. Only Basin is forecast to need capacity in 2018.[15] In total, known market transactions, generation resources, load requirements, and the optimization of transfers within WECC show adequate market depth to maintain positive target reserve margins for several years.

[13] Market liquidity refers to having ready and willing buyers and sellers for large transactions.
[14] The Northwest is comprised of the Pacific Northwest and Montana.
[15] Langely Gulch and Lake Side 2, as discussed earlier, will defer Basin's need until 2019.

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

The Pacific Northwest Resource Adequacy Forum issued resource adequacy standards in April 2008, which were subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year. The 2008 analysis of 2011 through 2013, conducted before the economic downturn, indicated that "the region has ample supplies over the next five years to avoid significant power curtailments."[16] A resource adequacy report update for 2015 is under development. However, the resource adequacy methodology is now undergoing review. The release of the 2015 report is now expected sometime in 2011. Based on WECC's adequacy evaluation, the Pacific Northwest adequacy situation is expected to remain adequate through 2015 and beyond.

Market Reliance Stress Test

Market Stress Test Design

PacifiCorp's underlying assumptions for the stress test are as follows:

- Based on the WECC resource adequacy assessment, the market reliance risk does not become a factor until at least 2015. Consequently, the market stress period was defined as 2015 through 2020.
- Availability of front office transactions for this period is reduced to 50% of levels assumed for development of the test portfolio.
- Market prices experience a corresponding increase, reflecting reduced market liquidity; the June 2008 Official Forward Price Curve was applied to simulate high market prices as shown in Figure H.6
- To make up for the reduced front office transaction availability, PacifiCorp assumed that it would lease mobile simple-cycle combustion turbine units with a fixed cost of $267/kW for a three-month period (July-September). The annual SCCT capacity requirement ranges from 330 to 550 MW to cover the lost FOT capacity.

PacifiCorp selected a portfolio from the core case group, Case 14, as the test portfolio for the analysis. Case 14 had the highest front office transaction reliance of the core case portfolios for 2015 - 2020. Table H.1 shows the replacement SCCT resource capacity added to the portfolio by year to make up for the reduced FOT, as well as the annual dollars/kW fixed cost assumed for leasing the peaking units.

The Company then simulated this portfolio with the Planning and Risk model, applying the above set of market stress assumptions. Portfolio cost (stochastic mean PVRR and stochastic upper-tail mean PVRR) are compared against the original stochastic run for Case 14.

[16] The Pacific Northwest Resource Adequacy Forum's Web page can be accessed with the following link: http://www.nwcouncil.org/energy/resource/Default.asp. The 2008 resource assessment paper is available for download.

Figure H.6 – Front Office Transaction Market Price Comparison

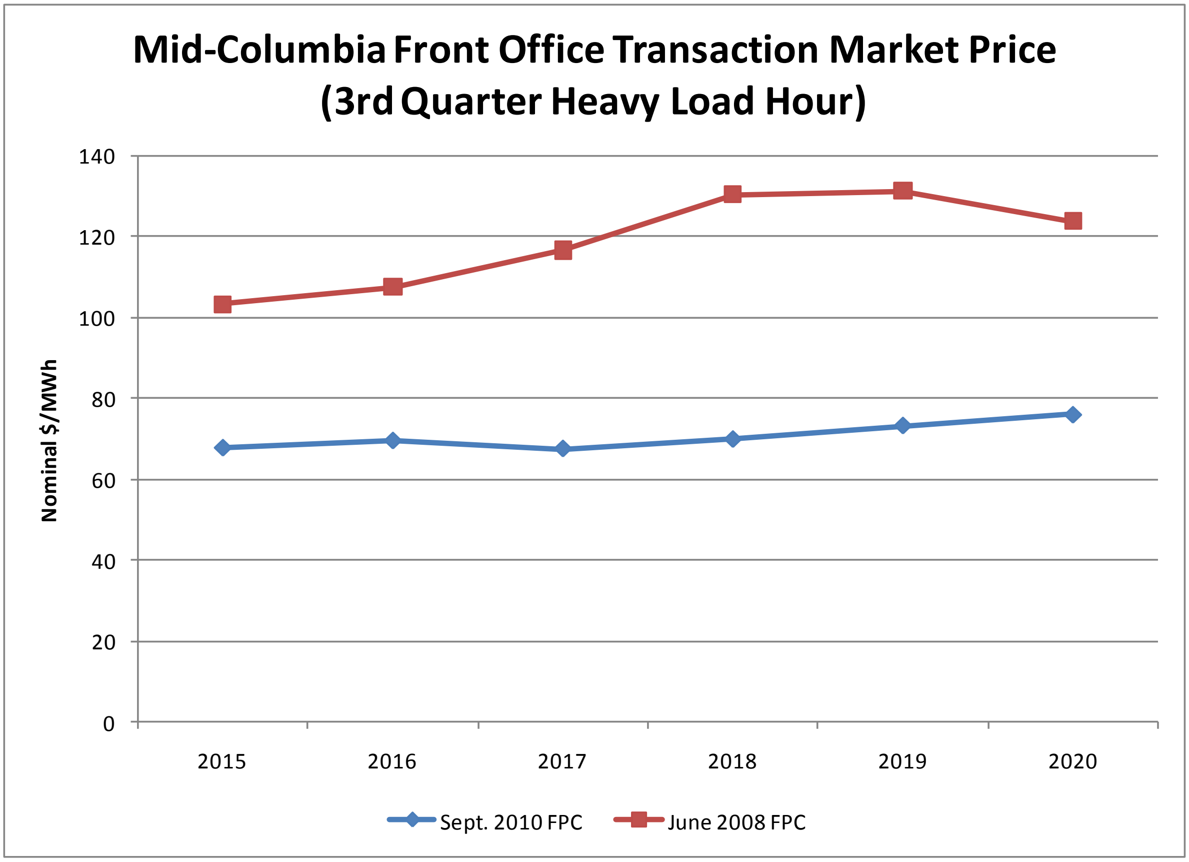


Table H.1 – Peaking Resource Megawatt Capacity Requirements and Fixed Costs

FOT Product and Location	2015	2016	2017	2018	2019	2020
Mead Q3, Heavy Load Hour	50	50	0	0	0	0
Utah Q3, Heavy Load Hour	100	94	100	0	0	100
Mona, Q3, Heavy Load Hour	150	150	150	150	150	150
COB Q3, Heavy Load Hour	25	0	0	0	0	0
Mid-Columbia Q3, Heavy Load Hour	200	200	200	184	197	200
West Main Q3, Heavy Load Hour	25	25	25	0	0	25
Total	550	519	475	334	347	475
Annual Fixed Cost of Peaking Resources, 2010$	$36,683,030	$34,624,326	$31,706,250	$22,272,873	$23,176,101	$31,706,250

Stress Test Results

Table H.2 reports the PVRR line items details for the base stochastic simulation and the stress test stochastic simulation. The stress test conditions resulted in a $387.3 million increase in the stochastic mean PVRR.

Table H.2 – Stochastic PVRR Details for Stress Test and Base Portfolio Simulations

Cost Component	Case 14	Stress Test Case 14	Case 14 less Stress Test Case 14
Variable Costs			
Fuel & O&M	8,461.6	9,312.7	851.1
Emission Cost	3,098.1	3,533.6	435.5
FOT's & Long Term Contracts	2,647.2	2,415.5	(231.7)
Demand Side Management	$1,715	$1,715	-
Renewables	$657	$671	13.35
System Balancing Sales	(3,389.3)	(4,273.9)	(884.6)
System Balancing Purchases	1,710.3	1,805.5	95.2
Energy Not Served	70.9	71.1	0.1
Dump Power	(23.0)	(24.0)	(1.0)
Reserve Deficiency	0.0	0.0	(0.0)
Total Variable Costs	14,947.9	15,225.7	277.8
Capital and Fixed Costs	2,973.2	3,082.6	109.4
Total PVRR	17,921.1	18,308.4	**$387.3**

The higher costs for the stress test portfolio are driven by greater generation costs resulting from increased thermal resource utilization to cover the replaced FOT, as well as the higher fixed costs of the replacement peaking units. These costs were partially offset by increased market sales and lower purchases stemming from use of the replacement peaking resources during peak periods.

Customer versus Shareholder Risk Allocation

Market purchase costs are reflected in rates. Consequently, customers bear the price risk of the Company’s reliance on a given level of market purchases. However, customers also bear the cost impact of the Company's decision to build or acquire resources if those resources exceed market alternatives and result in an increase in rates. These offsetting risks stress the need for robust IRP analysis, efficient RFPs and ability to capture opportunistic procurement opportunities when they arise.

APPENDIX I – WIND INTEGRATION STUDY

This appendix provides the 2010 Wind Integration Study conducted during the 2011 IRP planning process. This is the version sent to participants on September 1, 2010.

PacifiCorp

2010 Wind Integration Resource Study

September 1, 2010

2010 Wind Integration Resource Study

1. Executive Summary

The purpose of the 2010 Wind Integration Study (the "Study") is twofold. First, the Study quantifies how wind generation affects the amount of operating reserve needed to maintain historical levels of reliability. Second, the Study tabulates the cost of integrating wind generation by measuring how system costs change with changes in operating reserve demand and by measuring how system costs are affected by daily system balancing practices.

Based upon historical and simulated wind generation data and historical load data, the Study shows that operating reserve demand for both regulation reserve service and load following reserve service increases with higher wind penetration levels. For purposes of this Study, regulation reserve service refers to operating reserves required by variability in both load and wind over ten-minute time intervals and load following reserve service refers to operating reserves required by both load and wind variability over hourly time intervals. Table 1 summarizes how operating reserve demand for both regulation and load following services increases as wind penetration levels grow from approximately 425 MW to approximately 1,833 MW. Table 2 depicts the change in operating reserve demand that is incremental to a load only calculation of the same types of reserve service.

Table 1. Annual average operating reserve demand by penetration scenario.

		Load Only	425 MW	1372 MW	1833 MW
West	Regulation Up	97	105	137	137
	Regulation Down	72	84	120	120
	Load Following Up	101	114	139	141
	Load Following Down	106	113	132	133
East	Regulation Up	138	140	201	231
	Regulation Down	107	110	185	222
	Load Following Up	139	144	207	245
	Load Following Down	144	147	198	237

Table 2. Annual average operating reserve demand incremental to the load only scenario.

		Load Only	425 MW	1372 MW	1833 MW
West	Regulation Up	0	7	39	39
	Regulation Down	0	12	48	48
	Load Following Up	0	13	38	39
	Load Following Down	0	7	26	27
East	Regulation Up	0	3	63	93
	Regulation Down	0	3	78	116
	Load Following Up	0	4	68	106
	Load Following Down	0	3	54	93

The costs of integrating wind as calculated in this Study include costs associated with increased operating reserve demand as outlined above and the costs from daily system balancing practices. Both types of costs were calculated using the Planning and Risk model (PaR), which is a production cost simulation model configured with a detailed representation of PacifiCorp's system. For each wind penetration scenario, a series of PaR simulations were completed to isolate each wind integration cost component by using a "with and without" approach. For instance, PaR was first used to calculate system costs without any incremental operating reserve demand and then again with the added incremental reserve demand. The change in system costs between the two PaR simulations drives the integration cost calculation. Table 3 summarizes the wind integration costs established in this Study alongside those costs calculated as part of the 2008 Integrated Resource Plan.

Table 3. Wind integration costs per MWh of wind generated as compared to those in the 2008 IRP.

Study	2008 IRP	2010 Wind Integration Study	2010 Wind Integration Study
Wind Capacity Penetration	2,734 MW	1,372 MW	1,833 MW
Tenor of Cost	20-Year Levelized	3-Year Levelized	3-Year Levelized
Interhour / System Balancing ($/MWh)	$2.45	$0.82	$0.86
Reserve ($/MWh)	$7.51	$8.03	$8.85
Total Wind Integration ($/MWh)	$9.96	**$8.85**	**$9.70**

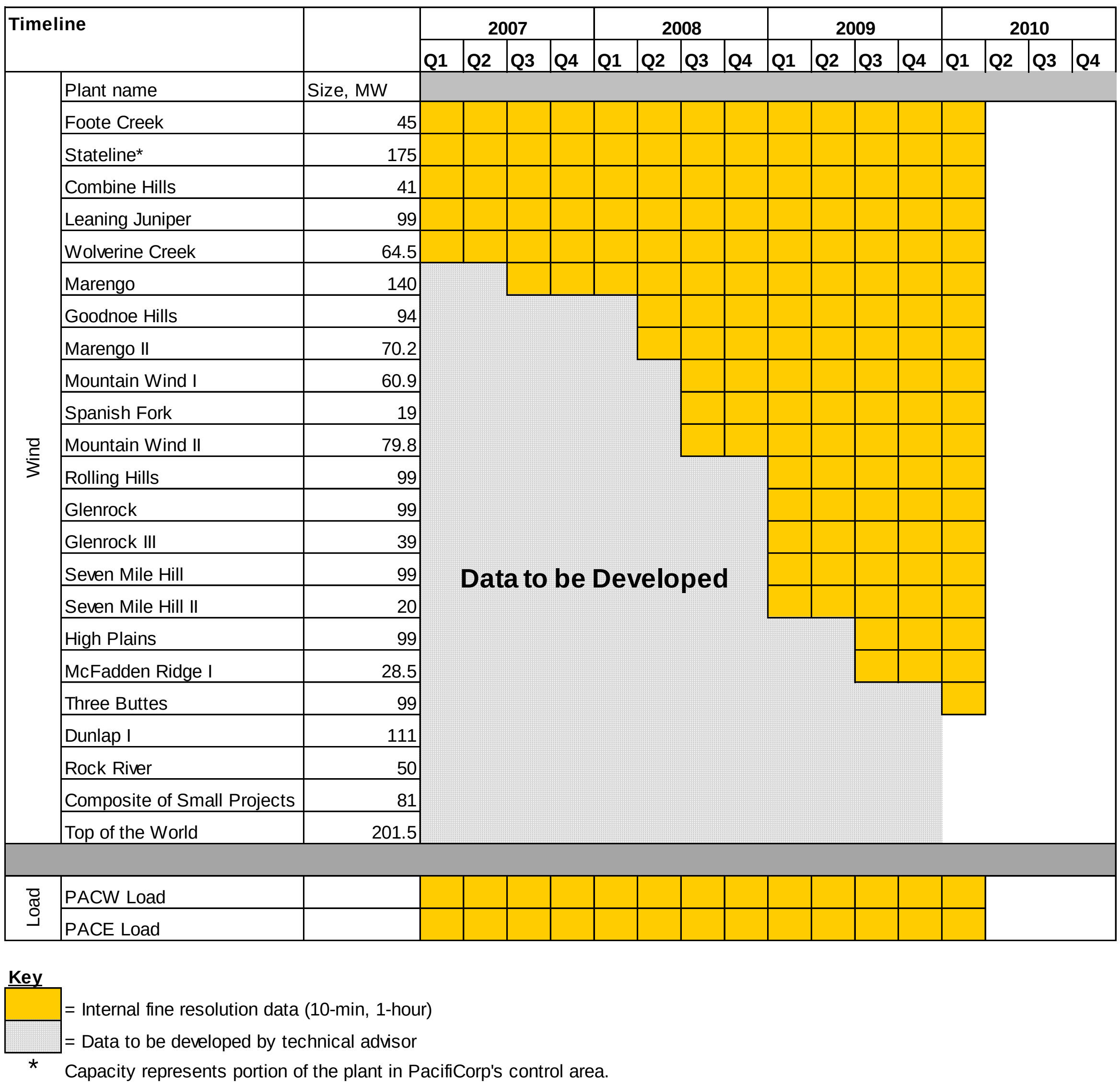
As shown above, the Study finds that operating reserve demand and the associated costs increase with wind capacity penetration. System balancing costs, driven by day-ahead forecast errors for wind and load, trend similarly as wind penetration increases from 1,372 MW to 1,833 MW; however, as expected, system balancing integration costs are much lower than integration costs for operating reserves.

2. Data Collection

2.1 Overview

The calculation of Operating Reserve demand was based on load and production data over the 2007 to 2009 period (the "Initial Term"). Figure 1 shows that over this period, ten-minute interval data was not available for all wind resources included in the Study. Nonetheless, PacifiCorp chose to use this data because it represented the best base of observed data available within the company, it includes significant concurrent load and wind generation data, and it includes year-on-year variability in weather and other variables affecting load and wind generation levels.

Figure 1. Raw historical wind production and load data inventory.



The data inventory summarized in Figure 1 contains as much real, observed, concurrent data as possible, owing to the volatile and unpredictable nature of wind generation output as well as the many fine variations available in real load data that can be difficult to capture with simulated data. Nonetheless, the data set selected for the Study contains gaps, and as a result, PacifiCorp utilized the services of the Brattle Group, the technical advisor that assisted with this study, to simulate missing wind data pertaining to the Initial Term. The simulation of wind data is discussed at length in its own section later in this report.

2.2 Historical Load and Load Forecast Data

The historical load data for the East and West Balancing Authority Areas was collected for the Initial Term from the PacifiCorp PI system[17]. These data were used for all the calculations involving historical load in the Study. The hourly day-ahead load forecasts were gathered from PacifiCorp's load forecast group, as were the day-ahead hourly load forecasts used to set up the generation system through the Initial Term period.

2.3 Historical Wind Generation and Wind Generation Forecast Data

2.3.1 Overview of the Wind Generation Data Used in the Analysis

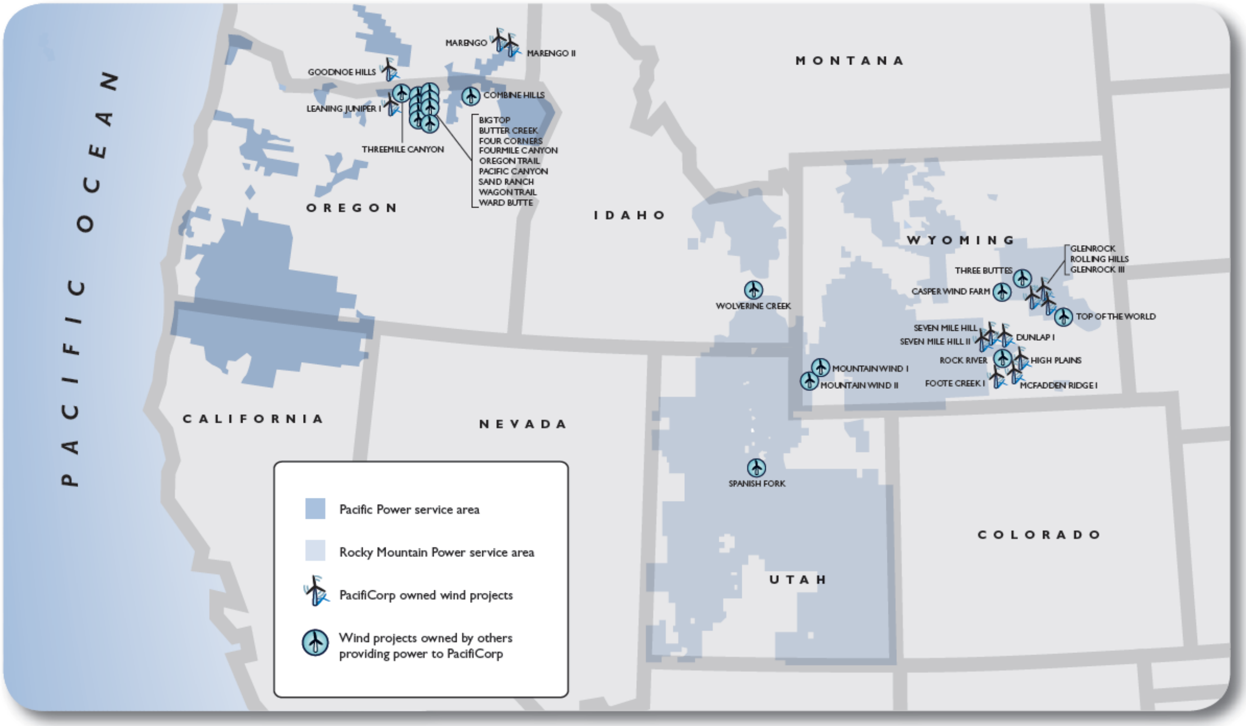
Ten-minute interval metered wind generation data were available for a subset of the wind sites as summarized in Figure 1. The wind output data were collected by PacifiCorp at each physical project location using the PI software system. In addition to historical wind generation data, the Study required historical day-ahead wind forecasts, modeled day-ahead wind forecasts for simulated data, and the creation of an ideal wind profile. All of these data sets were needed to establish wind integration costs using PaR and are discussed in turn below.

2.3.2 Historical Wind Generation Data

As shown in Figure 2, a cluster of PacifiCorp owned and contracted wind generation plants is located in Pacific Power's service area (PacifiCorp's West Balancing Authority Area) and another is located in the Rocky Mountain Power service area (PacifiCorp's East Balancing Authority Area). It is worth noting that two wind sites, Wolverine Creek in Idaho, and Spanish Fork in Utah are part of the East Balancing Authority Area, but are geographically distant from both the western and the eastern clusters.

[17] The PI system collects load and generation data and is supplied to PacifiCorp by OSISoft http://www.osisoft.com/software-support/what-is-pi/what_is_PI_.aspx .

Figure 2. Map of PacifiCorp wind generating stations used in this study.



The available historical ten-minute wind generation data were examined to produce some initial statistical diagnostics for each site and between sites. For each site, Table 4 shows: (1) number of 10-minute interval data observations available, (2) standard deviation of observed capacity factors, (3) the minimum capacity factor, and (4) the maximum capacity factor. Small negative capacity factor values (that show up as the minimum) in the data are the result of power consumption associated with routine operation of the wind projects even during times when the project itself is not producing energy. Table 5 shows the correlation observed among aggregate hourly load and wind generation data in 2008. By and large, hourly changes in load and wind generation output, which drive operational planning, do not appear to be correlated.

Table 4. Statistical properties of wind site capacity factor data.

Plant Name	Number of Observations	Standard Deviation	Min	Max
Goodnoe	83,520	32%	0%	100%
Leaning Juniper	157,824	35%	0%	100%
Combine Hills	157,824	38%	-3%	100%
Stateline	157,824	24%	-1%	100%
Marengo	79,776	33%	-11%	100%
Wolverine Creek	157,824	29%	-1%	100%
Spanish Fork	74,736	29%	-4%	87%
Mountain Wind	66,096	29%	0%	100%
Foote Creek	157,824	30%	-2%	100%
Seven Mile Hill	52,704	31%	0%	100%
McFadden Ridge	11,952	34%	-1%	100%
High Plains	15,840	21%	0%	67%
Glenrock	50,256	29%	0%	100%

Table 5. Hourly correlation of system wind and system load.

	Overall	Rolling 6 hour	Rolling 12 Hour
January	-2.5%	-2.9%	-3.4%
February	-2.8%	-0.6%	-1.7%
March	-0.4%	-1.4%	-2.2%
April	-6.4%	-3.5%	-5.9%
May	-10.4%	-3.0%	-6.4%
June	-12.0%	-9.2%	-11.9%
July	-12.4%	-12.3%	-14.2%
August	-9.1%	-8.4%	-9.8%
September	-6.5%	-0.6%	-4.0%
October	-3.5%	-4.8%	-6.7%
November	-7.5%	-3.6%	-4.4%
December	-2.0%	0.3%	-1.1%

2.3.3 Historical Day-ahead Wind Generation Forecasts

Day-ahead wind forecasts were collected from daily historical files maintained by PacifiCorp commercial operations. The files contained day-ahead hour-by-hour wind generation forecasts for the wind projects operating during the Initial Term. For those projects not operating during the Initial Term, day-ahead forecasts were created using the daily volumetric day-ahead forecast error from projects having complete data sets. As such, these data were used to bootstrap[18] the daily day-ahead forecast volumetric errors for the 1,372 MW and 1,833 MW scenarios, and the daily error (positive or negative) was applied to simulated wind generation data to create a

[18] Bootstrapping is a common statistical method used to estimate data by extrapolating from existing data.

modeled day-ahead forecast. The modeled day-ahead forecast maintained the same general hourly shape as the simulated wind generation data but was shifted vertically hour-by-hour on an equal percentage basis to keep the aggregate volumetric error constant.

2.3.4 Ideal Shape Wind Generation

In order to isolate wind integration costs from other system costs, a flat production profile is required for PaR modeling. This profile, deemed the ideal wind shape for purposes of the Study, treats all the energy produced by wind projects as monolithic blocks. Comporting with standard trading products among forward energy markets in the Western Interconnect, the energy produced in each 16-hour daily block between hour ending seven and hour ending 22 was treated as a single block. Similarly, energy produced in the 8-hour block between hour ending 23 and hour ending six was treated as a single block. For each block, the total energy delivered from wind generation is averaged, thereby flattening the generation pattern.

2.4 Wind Generation Data Simulation

The technical advisor assisted PacifiCorp in developing the Study methodology and in supplementing the historical wind generation data with simulated ten-minute interval wind generation data. This section summarizes the methodology used to simulate wind generation data and provides sample data and graphics to illustrate the details involved in each step of the process.

The overall approach to simulating wind generation data involved taking an historical data inventory; addressing data quality issues in the data inventory; identifying gaps requiring simulation; and finding the best suited relationship between pairs of sites; and using that relationship to approximate the wind output for periods with missing historical observations. However, it is worth noting that for sites with no historical data, the necessary numerical relationships were estimated between relevant locations by using simulated wind data made available by the National Renewable Energy Laboratory (NREL). Additional detail on simulation procedures is available in Appendix A.

2.4.1 Categorization of Historical Wind Data to Determine Simulation Scope

The historical wind data were classified into three groups to determine the periods requiring simulation for each site. The three categories are defined in turn below, and Figure 3 depicts how each site was categorized.

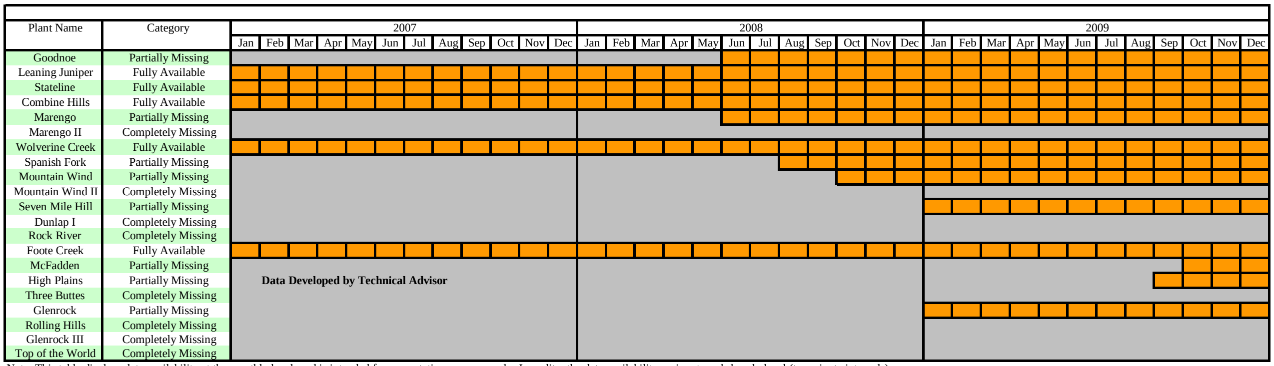
(1) *Fully Available*—this category refers to sites for which output data are available for the entirety of the Initial Term. Specifically, these wind plants include: Leaning Juniper, Combine Hills, Stateline, Wolverine Creek, and Foote Creek. These plants sum to 425 MW of capacity.

(2) *Partially Missing*—refers to sites for which output data are unavailable for a portion of the Initial Term. The wind plants that fall into this category are: Goodnoe Hills, Seven Mile Hill, Marengo, Spanish Fork, Mountain Wind, McFadden Ridge, High Plains, and Glenrock. One important feature of the partially missing data profiles is that the missing portions are always chronologically located at the beginning of the time period—once a

partially missing data profile begins, it contains no further data “holes”. These plants sum to 848 MW of capacity.

(3) *Completely Missing*—refers to wind projects, for which no output data are available for the 2007-2009 Initial Term. Those sites are: Dunlap I, Rock River, Rolling Hills, Three Buttes, and Top of the World. These plants sum to 560 MW of capacity.

Figure 3. Categorization of wind generation data.



Note: This table displays data availability at the monthly level, and is intended for presentation purposes only. In reality, the data availability varies at a sub-hourly level (ten minute intervals).

Legend:
Data available
Data developed by Technical Advisor

2.4.2 Simulation Process

The simulation process used in the Study evolved to become iterative in nature to ensure that simulated wind generation data used to establish operating reserve demand was reasonably aligned to the operating reserve demand calculated using observed wind generation data. As such, different methods of error sampling and simulation techniques (multiple linear, Tobit; for example) were evaluated in this manner. Tables 6 illustrates an example of how operating reserve demand calculated from observed and simulated data were used to evaluate different error sampling and re-addition methods used in this iterative process for the West Balancing Authority Area.

Table 6. Comparison of operating reserve demand calculated from actual wind generation plant data and simulated wind generation plant data estimated using a least squares regression and applying different scaling of errors added back into the raw prediction.

Actual Wind Generation Data			
	Load Following Up	Load Following Down	Regulation
	15.0	(19.1)	15.5
Test (Developed Wind Data)			
Error Scaling (%)	Load Following Up	Load Following Down	Regulation
10	9.9	(13.0)	11.1
50	10.6	(13.9)	12.3
75	11.7	(14.2)	14.3
100	12.4	(15.9)	17.1

Several simulation attempts ended with values above the feasible generation capacity range, or values beneath zero. Attempts to add the error term back into the prediction (a necessary simulation step) also faced significant hurdles in developing reasonable results. The highly variable ten-minute output led to error terms with ranges larger than the simulated values in many cases, which would also test the boundaries of either zero or maximum plant capacity delivered. Several processes were attempted to return a sampled error estimation back to the modeled estimate, per proper regression, including sampling of truncated error distributions, medians of the error distributions, and various bins of errors sampled and added back to the regression estimate. Various combinations of these methods were put through the operating reserve demand estimation calculations to assess whether the results were reasonable. Ultimately, the Tobit simulation method (described in more detail in section A.4.3) and a 3-step smoothed median of the sampled errors proved to offer reasonably stable results.

Ultimately, the iterative simulation process produced a simulation methodology comprised of several sequential steps:

(1) estimate the *Tobit* regressions;

(2) using the regression coefficients, generate estimates of the mean output of the *predicted variable*[19]

(3) calculate the regression residuals;

(4) randomly sample the residuals according to predefined simulated output ranges;

(5) apply a non-linear 3-step median smoother to the sampled residuals;

(6) add the smoothed residual series to the predicted mean output.

A more detailed description of each step appears in Appendix A, and the resulting regression coefficients appear in Appendix B.

[19] These are generally referred to in the literature as "y hat"

3. Methodology

3.1 Method Overview

This section of the Study presents the approach used to establish the enumeration of operating reserve demand and the method for calculating wind integration costs. Ten minute interval load and wind data is used to estimate the amount of operating reserve, both up and down, needed to manage fluctuations in load and fluctuations in wind within PacifiCorp's Balancing Authority Areas. The operating reserve discussed here is limited to spinning reserve and non-spinning reserve, which are needed for regulation, load following, and contingency reserve services. For purposes of this Study, regulation service refers to the operating reserve required to manage the variability of load and wind generation in ten minute periods, and load following service represents the operating reserve required to manage the variability as measured in hourly periods.[20] Contingency reserve, although mentioned, is supplied in accordance with the North American Reliability Corporation (NERC) standards and remains unchanged by the wind generation contemplated in this Study. Therefore, the operating reserve quantities discussed herein are only pertinent to supplying the demands of regulation and load following services, which are assessed in for load, and load net wind scenarios.

Once the amount of operating reserve is established for different levels of wind penetration, the cost of holding the reserve on PacifiCorp's system is calculated using PaR. In addition to using PaR for evaluating operating reserve cost, the PaR model is used to estimate wind integration cost associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions.

3.2 Incremental Operating Reserve Demand

A dense data set of ten-minute interval wind generation and system load drives the calculation of the marginal reserve requirement in two components: (1) regulation, which is developed using the ten-minute interval data, and (2) load following, which is calculated using the same data but estimated using hourly variability. The approach for calculating incremental operating reserve necessary to supply adequate capacity for regulation and load following at levels required to maintain current control performance was based on merging current operational practice with a survey of papers on wind integration, as well as advisory from the technical advisor.[21] The Initial Term load data is used as the baseline case (zero wind generation) in each scenario. Coincident wind data (as observed, plus that simulated by the technical advisor) were added in increasing levels of wind capacity penetration to gauge the change in operating reserve demand. For purposes of the Study, the regulation calculation compares observed ten-minute interval load

[20] PacifiCorp's definitions for regulation and load following are based on PacifiCorp's operational practice, and not intended to describe the operational practices or terminology used by other power suppliers or system operators.

[21] The external studies PacifiCorp has relied on can mostly be found on the Utility Wind Integration Group (UWIG) website at the following link: http://www.uwig.org/opimpactsdocs.html

and wind generation production to a ten minute interval estimate, and load following compares observed hourly averages to an average hourly forecast.

3.2.1 Regulation Operating Reserve Service Demand

With no sub-hourly clearing or imbalance market, PacifiCorp must plan to meet sub-hourly load (and load net of wind) deviations with its own resources. This includes generating units on automatic generation control (AGC), demand side management (DSM), and the ramping of flexible generation units in real time operation, which requires that existing units be committed and then dispatched to provide operating reserve. Wind variability among ten-minute intervals can represent a quantity of generation required to ramp up or down to maintain system stability. Regulation service demand for wind generation variability was considered first. To parse the ten-minute interval wind variability from the ensuing load following analysis, a persistence forecast of the rolling prior 60 minutes was used to analyze the variation of each ten minute interval. The actual wind generation in each ten minute interval was subtracted from the rolling average of the prior six ten-minute intervals, and the standard deviation was computed for each monthly period. This approach follows the one used by the National Renewable Energy Laboratory (NREL) for its recent "Eastern Wind Integration and Transmission Study".[22]

$$\mathbf{Regulation}_{\text{wind10min}} = \mathbf{P}_{\text{cps2}}\,(\mathbf{Wind}_{\text{i}})$$

Where:

$\mathbf{P}_{\mathbf{CPS2}}$ = The percentile of a two-tailed distribution equaling the Balancing Authority Area's CPS2 performance[23]

$\mathbf{Wind}_{\text{i}}$ = the wind forecast error defined as ($\mathbf{Wind}_{\text{Actual10min}}$ -$\mathbf{Wind}_{\text{10-min-forecast}}$)

$\mathbf{Wind}_{\mathbf{10\text{-}min\text{-}forecast}}$ = the rolling average of the wind generation in prior six ten-minute intervals, also referred to as a persistence forecast of the rolling prior 60 minutes

$\mathbf{Wind}_{\mathbf{Actual10min}}$ = the observed wind generation for a given ten-minute interval

The load variability and uncertainty was analyzed comparing the ten-minute actual load values to a line of intended schedule, which was represented by a line interpolated between an actual top-of-the-hour load value and the next hour's load forecast target at the bottom of that (next) hour. A sample of how the intended schedule compares to actual load data is shown in Figure 4. The method approximately mimics real time operations process for each hour. At the top of the given hour, the actual load is known and a forecast for the next hour was made. For the purposes of this study, a line joining the two points was made to represent the ideal path for the ramp or decline expected within the given hour. The resulting actual ten-minute load values were compared to this straight line so as to produce a strip of error terms, as depicted in Figure 5 with data from February 2009.

[22] NREL, *Eastern Wind Integration and Transmission Study*, prepared by EnerNex Corporation, (January 10, 2010), p. 143. The report is available for download from the following hyperlink: http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

[23] The Control Performance 2 is a reliability standard is maintained by the North American Electric Reliability Council. A definition is available on page 3of the document at the following hyperlink: http://www.nerc.com/files/Reliability_Standards_Complete_Set_2010Jan25.pdf

The errors were assembled monthly and their Regulation demand estimated similarly to the method used for the 10-minute values of the wind data:

$$\mathbf{Regulation}_{\text{load10min}} = \mathbf{P}_{\text{cps2}}\,(\mathbf{Load}_{\text{i}})$$

Where:

$\mathbf{Load}_i$ = the load forecast error, calculated similarly to $\mathbf{Wind}_i$

Figure 4. Sample of intended schedule ten-minute load estimate and observed system load.

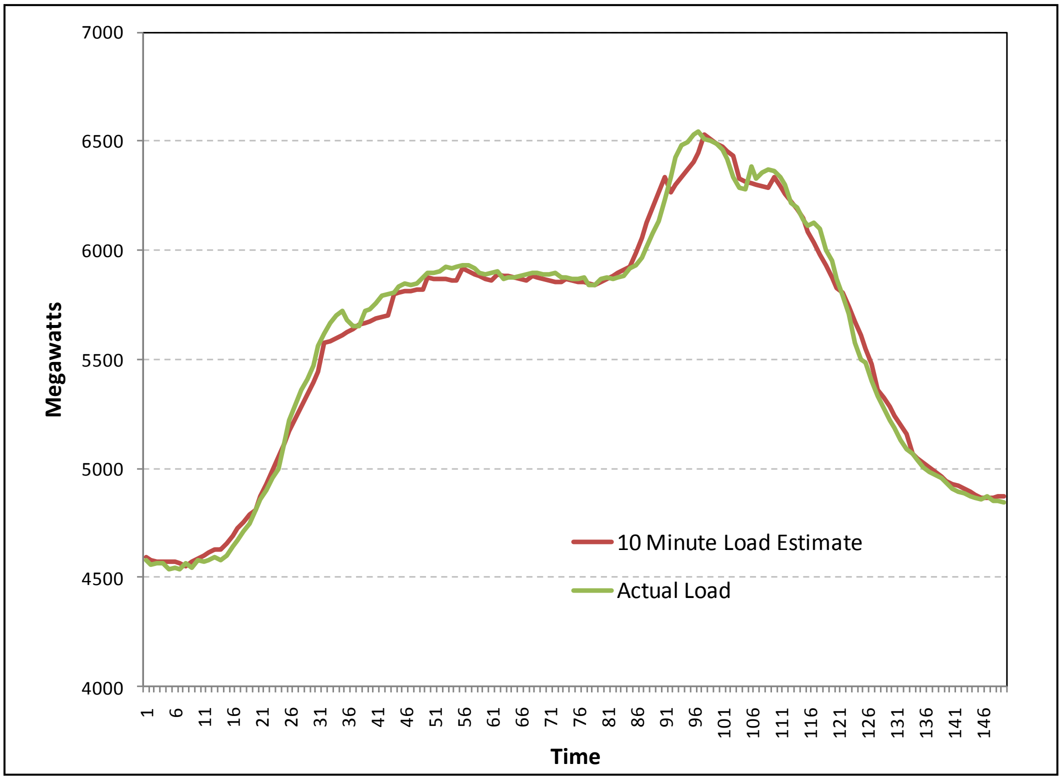
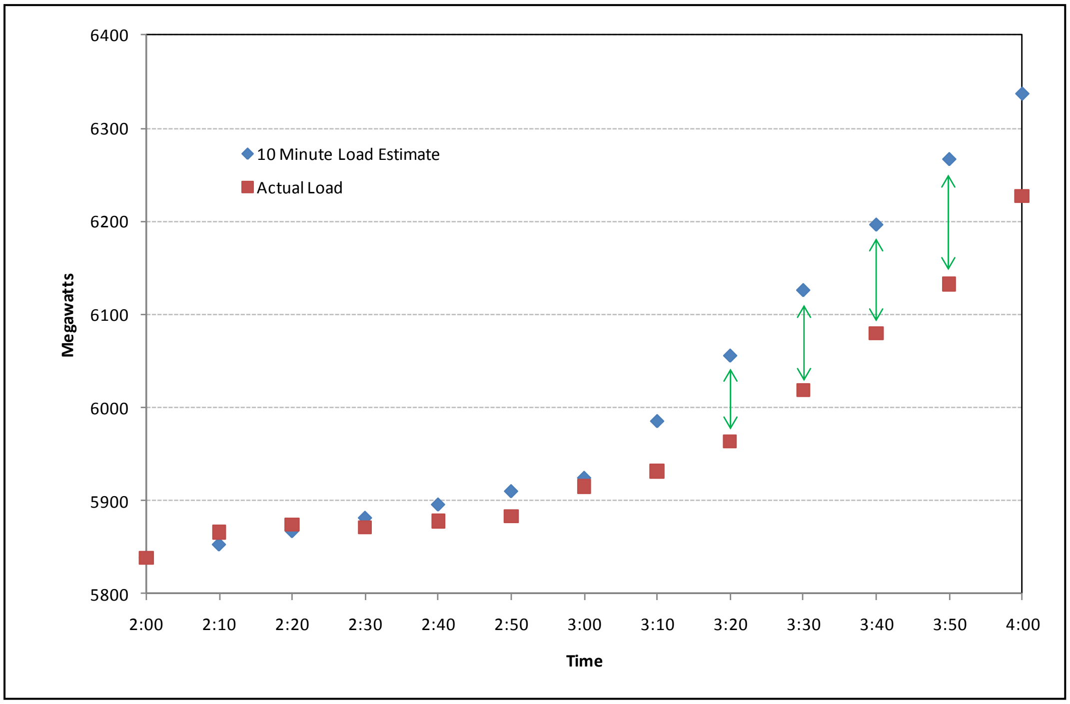


Figure 5. Variability between the line of intended schedule and observed load with errors highlighted by green arrows.

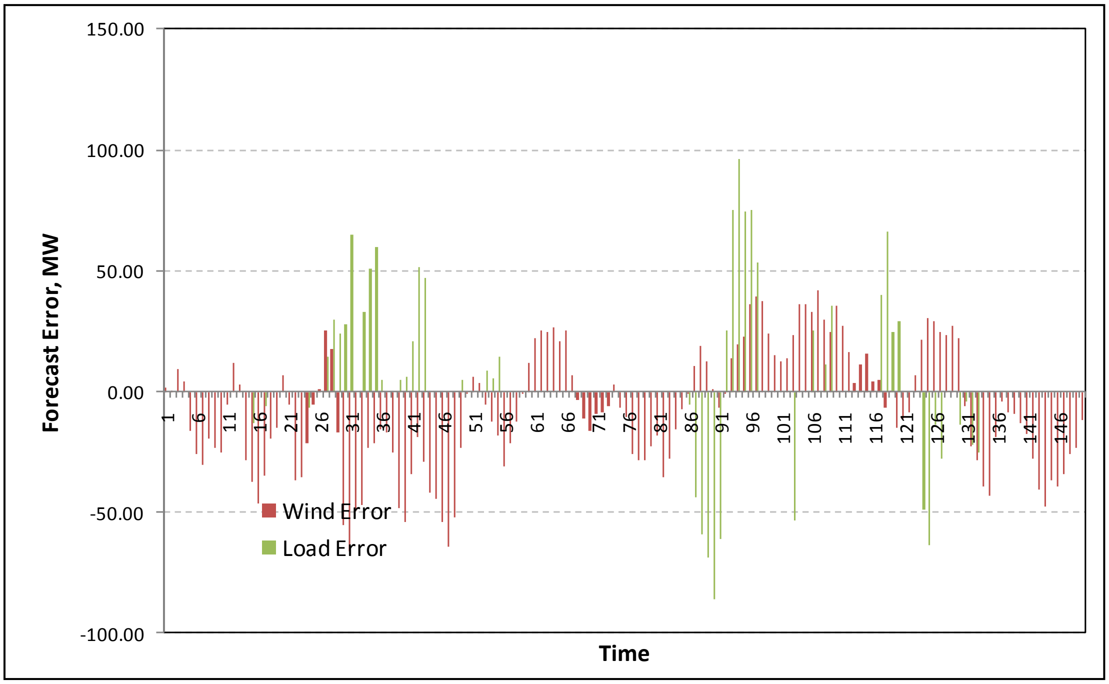


As the ten-minute load and wind errors each represent unpredictable change in the need for dispatchable generation, their variability was assessed separately and combined. The regulation demand of load net wind generation was estimated assuming short term variations in load are not correlated with changes in aggregate wind generation output through the use of a geometric average (shown for Regulation Up):

As the need for regulation service can vary whether the wind is up or down, both Regulation Up and Regulation Down services were estimated at each end of the error distributions.

A sample of the errors logged for the same period, for load and wind, are shown in Figure 6. The independence of the forecast errors for wind and load was assumed. These errors, or differences between forecast and actual, comprised an estimate of the demand made on regulation service operating reserves during power system operations. These differences were calculated for every ten minutes of operation through the Initial Term period, and separated into monthly bins for further analysis.

Figure 6. Independent forecast errors in ten-minute interval load and wind generation (December 2008, approximately 890 MW of wind penetration).



Analyzing the results on a monthly basis as opposed to grouping all the calculations together annually allowed for the fact that some months' power service actually required less regulation (for example, July and August) than others, and so costs could be more accurately attributed with a weighted average of results as opposed to grouping the entire year's operations into a single analysis bin. This is due to operating reserve being employed to manage the tails of the distributions involved, and a single annual bin would apply the greatest tail occurrences to the entire year, as opposed to only the month in which it occurs. Figure 7 demonstrates the resulting distributions of regulation demand for wind generation, where regulation down demand is the negative side of the distribution. The vertical lines drawn on Figure 7 illustrate the operating reserve threshold defined in the Study and data labels are added to denote outlying data points. Similarly, Figure 8 illustrates the resulting distribution of regulation demand for load, where regulation up demand is the positive side of the distribution.

Figure 7. Wind Regulation errors plotted for the Mays of the Initial Term at the 1,372 MW wind capacity penetration level.

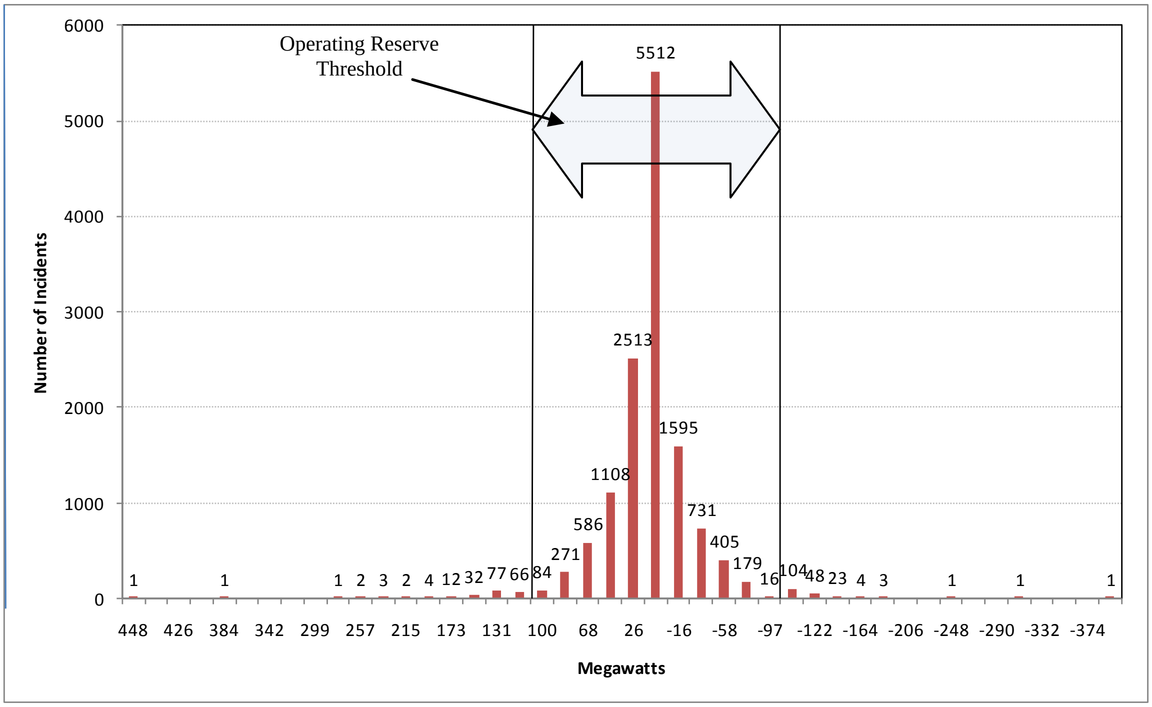
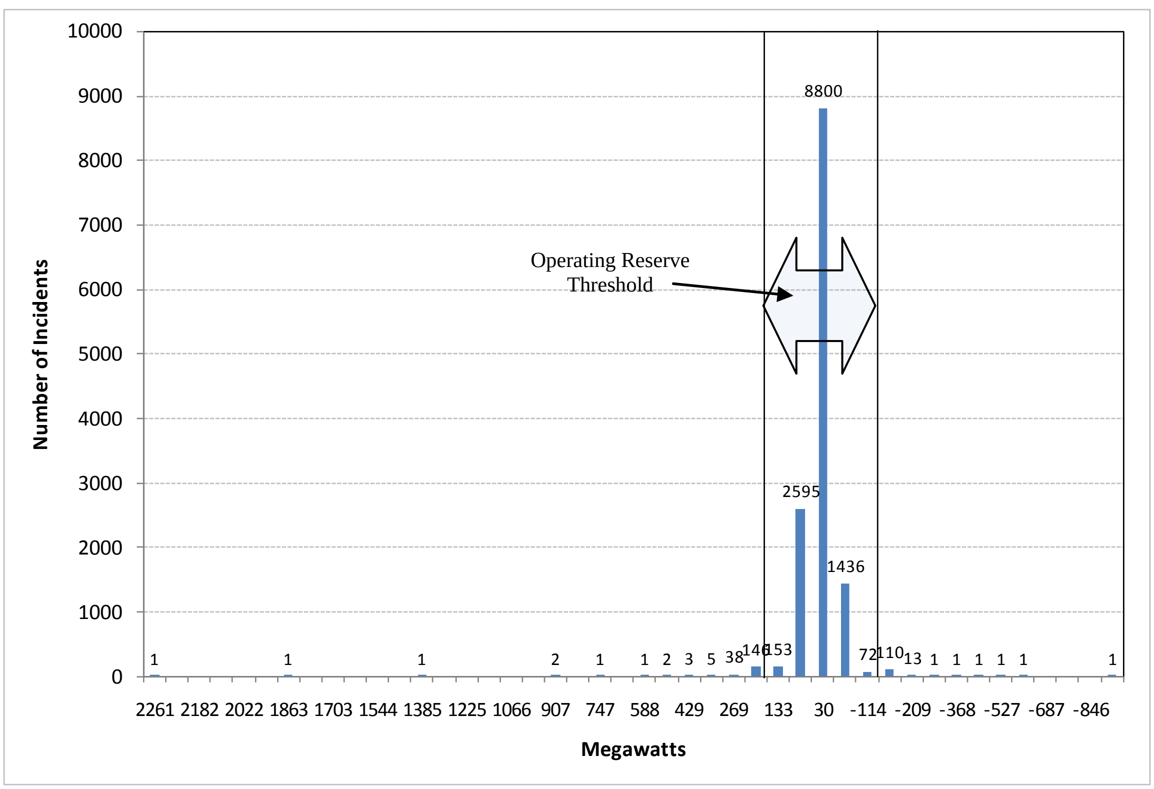


Figure 8. Load Regulation errors plotted for the Mays of the Initial Term.



3.2.2 Load Following Operating Reserve Demand

PacifiCorp maintains system balance by optimizing its operations to an hourly forecast with changes in generation and market activity. This planning interval represents hourly changes in generation which are assessed within roughly 20 minutes each hour to account for a bottom-of-the-hour (:30 after) scheduling deadline. Taking into account the conditions of the present and the expected load and wind generation, PacifiCorp must schedule generation to meet demands with an expectation of how much higher or lower system load (net of wind generation) may be.

PacifiCorp's real-time desk updates the next hour's system load forecast forty minutes prior to each operating hour. This forecast is created by comparing the current hour load to the load of a similar-load-shaped day. The hour-to-hour change in load from the similar day and hours (the load delta) was applied to the "current" hour load and the sum is used as the forecast for the ensuing hour. For example, on a given Monday the PacifiCorp operator may be forecasting hour to hour changes in system load by referencing the hour to hour changes on the prior Monday, a similar-load-shaped day. If the hour to hour load change between the prior Monday's like hours was 5%, the operator will use a 5% change in load as the next hour forecast.

As for the corresponding short term operational wind forecast, the hourly wind forecast is done by persistence; applying the instantaneous sample of the wind generation output 20 minutes past the current hour to the next hour as a forecast and balancing the system to that point. The resulting operational modeling process therefore went as follows; at the top of the hour, wind generation output, dispatchable generation output, and load values were summarized, and trended using the methods above. The result was compared to the next hour's schedule for gaps as soon as possible, with the generation and load values updated at roughly 20 minutes past the hour. In real time operations, this result would then be balanced through a combination of market transactions and scheduling adjustments to PacifiCorp resources to produce a balanced schedule for the ensuing hour; with all transactions having to be complete by 30 minutes past the hour. Meanwhile, for purposes of the calculation made in this Study, the hourly wind forecast consisted of the 20th minute output from the prior hour, and the load forecast was modeled per the approximation described above with a shaping factor calculated using the day from one week prior, and applying a prior Sunday to shape any NERC holiday schedules.

Using the Initial Term data for PacifiCorp's Balancing Authority Areas, a comparison of the load and wind forecasts was implemented to measure the seasonal or annual trends in the variability between the hourly interval load and wind forecasts and the observed average hourly load and wind generation values. These differences were segmented into bins by load magnitude and wind generation magnitude using load and wind data, in order to facilitate making a weighted average of the reserves demand by load level and wind generation output level. An example of load and wind data segmented into bins appears in Figures 9 through 12. Figure 9 depicts forecast load in West Balancing Authority Area with a range of over and under predictions tied to Control Performance 2 (CPS2) performance level. Figure 10 shows the same data for the East Balancing Authority Area. In similar fashion, Figure 11 displays forecasted wind generation in the West Balancing Authority Area with a range of over and under predictions consistent with a

97% CPS2 performance level. Figure 12 shows the same wind generation forecast data for the East Balancing Authority Area.

Figure 9. Example of bin analysis for load following reserve service from load variability in the West Balancing Authority Area (May 2007-2009).

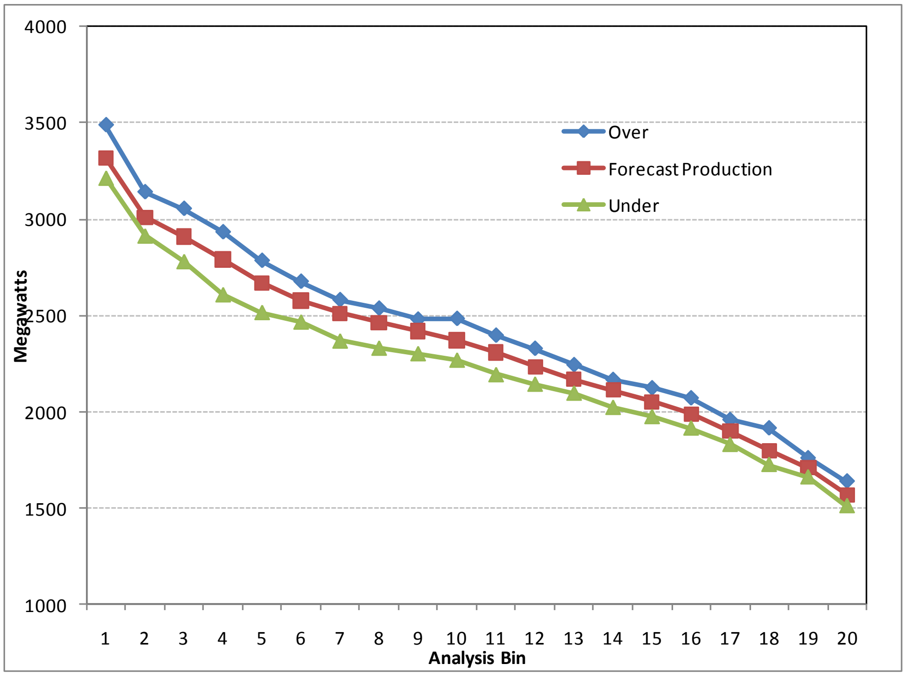


Figure 10. Example of bin analysis for load following reserve service from load variability in the East Balancing Authority Area (May 2007-2009).

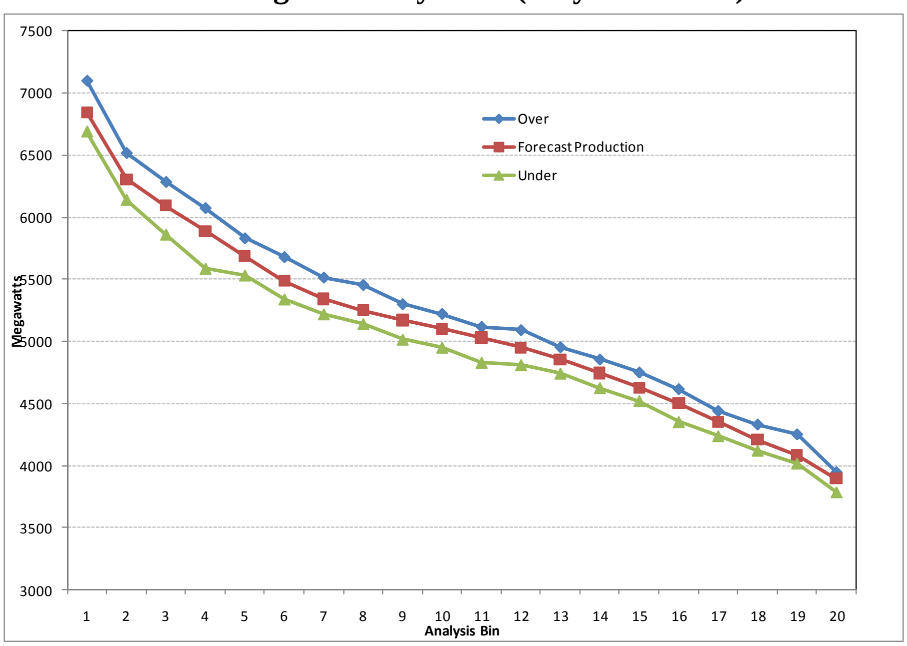


Figure 11. Example of bin analysis for load following reserve service from wind variability at the 1,372 MW penetration level for the West Balancing Authority Area (May 2007-2009).

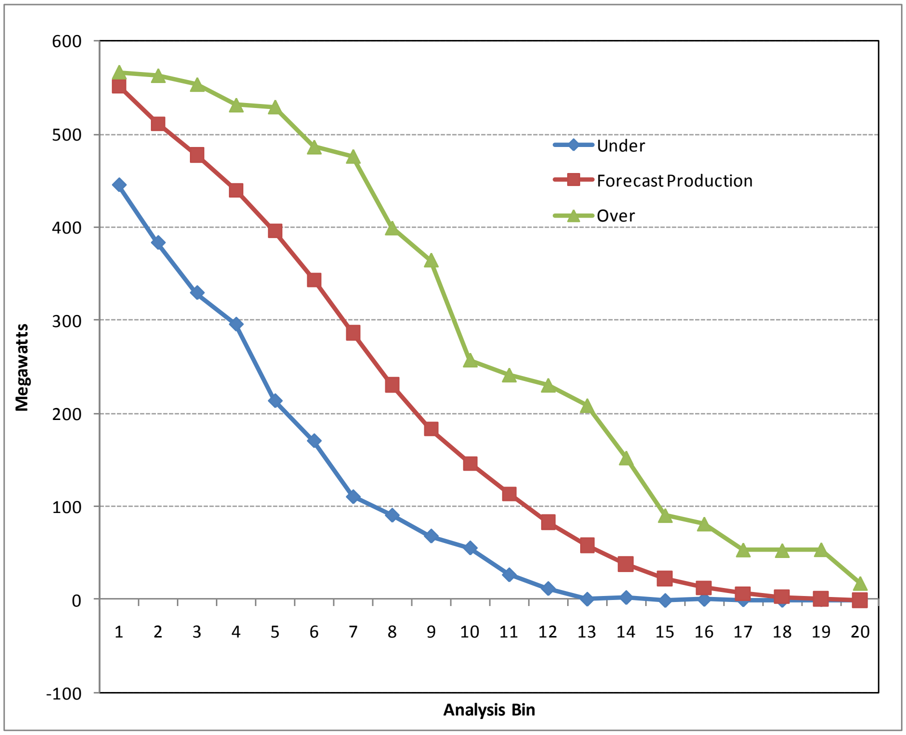
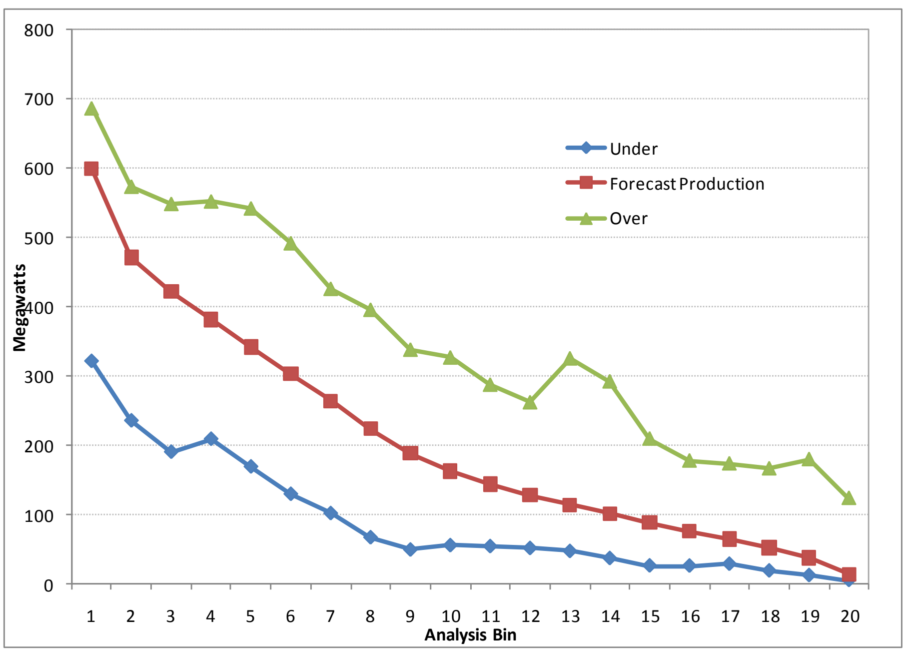


Figure 12. Example of bin analysis for load following reserve service from wind variability at the 1,372 MW penetration level for the East Balancing Authority Area (May 2007-2009).



Probabilities implied by the population of each bin, representing the expected amount of time spent in each load state, were represented by the historical data. The percentile equivalent to the historical CPS2 performance of PacifiCorp was sampled above and below the median of each of the bins. The average CPS2 performance for PacifiCorp's East and West Balancing Authority Areas over the period 2004 to 2009 was just below 97%. As the goal of this Study is to incorporate wind integration in PacifiCorp's current operations, the CPS2 performance of 97% was emphasized in these calculations. An assessment of the overall system power quality is a standalone topic that is beyond the scope of this Study, and thus, the Company assumed this level of reliability will be maintained. The difference between the CPS2 percentiles and the median of the bins represents the implied incremental load following service for operating reserve demand within that bin. As each respective bin also has an implied probability by the number of data points falling within it, the volumetric position over the study period was calculated as a simple weighted average.

To further explain the calculation method for load following reserve demand, the following example follows from the illustration in Figure 10. To assess the load following up reserve position for Bin 5, subtract the lower bound value (5,532 MW) from the system load forecast of 5,687 MW to arrive at an estimate of 154 MW for the occurrences within that bin. Integrating this process through all bins produced a composite load following up position for the East Balancing Authority Area in May, and the process was repeated for each month in the up and down directions. Wind generation was analyzed in exactly the same procedure, but with generation output representing the individual state variable. The wind and load reserve positions were combined using the root sum square calculation in each direction (up and down), assuming their variability in the short term is independent.

3.3 Determination of Wind Integration Cost

3.3.1 Overview

Owing to the variability and uncertainty of wind generation, each hour of power system operations features a need to set aside increased operating reserve (both spinning and non-spinning reserve), in addition to those set aside explicitly to cover load and contingency events which are inherent to the PacifiCorp system with or without wind. Additional costs are incurred with daily system balancing practice that is influenced by the unpredictable nature of wind generation on a day-ahead basis. To derive how wind generation affects operating reserve costs and system balancing costs, the Study utilizes the PaR model.

PacifiCorp's PaR model, developed and licensed by Ventyx Energy LLC, uses the PROSYM chronological unit commitment and dispatch production cost simulation engine and is configured with a detailed representation of the PacifiCorp system. For this study, four different PaR simulations were developed for a range of wind penetration scenarios as defined in Table 7. By carefully designing the four simulations, we were able to isolate wind integration costs associated with operating reserves and to separately calculate wind integration costs associated with system balancing practice. The former reflects integration cost that arises from short-term (within the hour and hour ahead) variability in wind generation and the latter reflects integration costs that arise from errors in forecasting load and wind generation on a day-ahead basis.

Table 7. Wind penetration scenarios used in PaR, as a percentage of total fleet capacity.

Representative Timing	Baseline	2007 End of Year	2009 End of Year	2010 End of Year
Installed Wind Capacity (Megawatts)	0	425	1,372	1,833
Wind Penetration Percentage	0%	3%	10%	12%

The four PaR simulations used for each penetration scenario in the Study are summarized in Table 8. The first two simulations are used to tabulate operating reserve wind integration costs, while the third and forth simulations support the calculation of system balancing wind integration costs. Table 8 identifies how key input variables change among the simulations. The simulations were run over the 2011 to 2013 forward term (three years), wherein 2007 wind generation and load data are used as inputs for 2011, 2008 wind generation and load data are used for 2012, and 2009 wind generation and load data are used for 2013. This calculation method combines the benefits of using actual system data available for the historic three-year Initial Term period with current forward price curves pertinent to setting the cost for wind integration service on a forward basis.[24] PacifiCorp resources used in the simulations are based upon the 2008 IRP Update resource portfolio.[25]

[24] The Study uses the March 31, 2010 official forward price curve.

[25] The 2008 Integrated Resource Update report, filed with the state utility commissions on March 31, 2010. The report is available for download from PacifiCorp's IRP Web page using the following hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2008IRPUpdate/PacifiCorp-2008IRPUpdate_3-31-10.pdf

Table 8. Wind integration cost simulations in PaR.

PaR Model Simulation	Forward Term	Load (Initial Term)	Wind Profile (Initial Term)	Incremental Reserve	Day-ahead Forecast Error
1	2011 - 2013	Actual	Ideal Shape	None	None
2	2011 - 2013	Actual	Actual	Yes	None
Operating Reserve Integration Cost = System Cost from PaR simulation 2 less system costs from PaR simulation 1					
3	2011 - 2013	Day-ahead Forecast	Day-ahead Forecast	Yes	None
4	2011 - 2013	Actual	Actual	Yes	Yes (Commitment from PaR Simulation 3)
System Balancing Integration Cost = System Cost from PaR simulation 4 less system costs from PaR simulation 2					

3.3.2 Calculating Operating Reserve Wind Integration Costs

To assess the effects of various levels of wind capacity added to the Balancing Authority Areas on operating reserve costs, each penetration scenario was simulated in PaR using both ideal (Simulation 1) and actual (Simulation 2) wind profiles. Both the ideal and actual PaR simulations excluded System Balancing costs. The ideal wind profile is a "flattened" representation of the actual profile, where wind generation is averaged across on- and off-peak blocks. Such a profile requires no additional operating reserve to support wind generation variability, and as such, Simulation 1 only included an operating reserve needed for load variability. In summary, Simulation 1 included actual historical loads, ideal wind profiles, and no incremental operating reserve to account for wind variability.

Simulation 2 used the actual wind generation profiles, which reflect the 2007 to 2009 observed and developed Initial Term wind data as inputs for the 2011 to 2013 forward period. These actual wind generation profiles reflect the same variability used to derive the incremental operating reserve requirements needed to integrate wind generation. Thus, the second PaR simulation includes the incremental operating reserve demand created by the variable nature of wind generation as well as the actual, variable wind generation profiles.

The system cost differences between these two simulations were divided by the total volume of wind generation in each penetration scenario to derive the wind integration costs associated with having to hold incremental operating reserve on a per unit of wind production basis.

3.3.3 Calculating System Balancing Wind Integration Costs

PacifiCorp conducted another series of PaR simulations to estimate daily system balancing wind integration costs consistent with the wind penetration scenarios studied. In this phase of the analysis, PacifiCorp generation assets were committed consistent with a day-ahead forecast of wind and load, but dispatched against actual wind and load. To simulate this operational behavior, two additional PaR simulations were necessary for each wind penetration scenario.

Simulation 3 was used to determine the unit commitment state of generation assets given the day-ahead forecast of wind generation and load. Simulation 4 used the unit commitment state from Simulation 3, but dispatches units based on actual wind generation and load. This actual wind and load data is pulled from the Initial Term , and thus, is identical to the actual wind generation and load inputs used to derive operating reserve wind integration costs as described above. In both of these PaR simulations, the amount of incremental reserve required for each penetration scenario was applied.

The change in system costs between Simulation 4 and the system costs from Simulation 2 already produced in the estimation of operating reserve integration costs isolates the wind integration cost due to system balancing. Dividing the change in system costs by the volume of wind generation in each penetration scenario produced a system balancing integration costs on a per-unit of wind production basis.

3.3.4 Allocation of Operating Reserve Demand in PaR

PaR Simulations 2 through 4 require operating reserve demand inputs that must be applied consistent with the ancillary services structure native to the model. The PaR model distinguishes reserve types by the priority order for unit commitment scheduling, and optimizes them to minimize cost in response to demand changes and the quantity of reserve required on an hour-to-hour basis. The highest-priority reserve types are regulation up and regulation down followed in order by spinning, non-spinning, and finally, 30-minute non-spinning.[26] Reserve requirements in the model need to be allocated into these PaR reserve categories and are expressed as a percentage of load.

The regulation up and regulation down reserves in PaR are a type of spinning reserve that must be met before traditional spinning and non-spinning reserve demands are satisfied. The incremental operating reserve demand needed to integrate wind generation was assigned in PaR as regulation up and regulation down. The traditional spinning and non-spinning reserve inputs are used for contingency reserve requirements, which remain unchanged among all PaR simulations in the Study. The 30-minute non-spinning reserve is not applicable to PacifiCorp's system, and thus it is not used in this Study.

[26] In PaR, spinning reserve is defined as unloaded generation which is synchronized, ready to serve additional demand and able to reach reserve amount within 10 minutes. Non-spinning Reserve is defined as unloaded generation which is non-synchronized and able to reach required generation amount within 10 minutes.

Note that given the hourly granularity in PaR, there is no distinction between operating reserve categorized as regulation and load-following in terms of how the model optimizes their use. Thus both regulation reserve service demand and load following reserve service demand are combined as a geometric average and input in PaR as regulation up and regulation down. Further, owing to the hourly granularity of PaR and the fact that PaR optimizes dispatch for each distinct hour, regulation reserves are effectively released for economic dispatch from one hour to the next. The PaR model requires separate inputs for spinning operating reserve and non-spinning operating reserve. Table 9 summarizes how the services for operating reserves are applied in PaR.

Table 9. Allocation of operating reserve demand to regulation, spinning and non-spinning reserve categories in PaR.[27]

Reserve Service	PaR Regulation Up	PaR Regulation Down	PaR Spinning Reserves	PaR Non-Spin Reserves
$\text{RegulationUp}_{10Min}$	$\text{RegulationUp}_{10Min}$	0	0	0
$\text{RegulationDown}_{10Min}$	0	$\text{RegulationDown}_{10Min}$	0	0
Load Following Up	Load Following Up	0	0	0
Load Following Down	0	Load Following Down	0	0
Contingency	0	0	0.5*(5% of Hydro and Wind Generation output + 7% of Thermal generation output)	0.5*(5% of Hydro and Wind Generation output + 7% of Thermal generation output)
Total	Geometric Average of the above	Geometric Average of the above	Sum of the above	Sum of the above

3.3.5 Satisfying Reserve Service Demand in PaR

PacifiCorp's thermal and hydro units are able to meet the reserve demand entered in PaR as shown in Table 10. Regulation reserve is typically held by units operating in automatic generation control (AGC) mode.

[27] Contingency Reserve is specified by the North American Energy Corporation in per http://www.nerc.com/files/BAL-STD-002-0.pdf .

Table 10. Reserve service capability of each generating unit in PaR.

Unit Name	Regulation Up	Regulation Down	Spin	Non-Spin
BEAR RIVER	No	No	No	Yes
CARBON 1	No	No	Yes	Yes
CARBON 2	No	No	Yes	Yes
CHEHALIS	Yes	Yes	Yes	Yes
CHOLLA 4	Yes	Yes	Yes	Yes
CLEARWATER 1 & 2	No	No	No	Yes
COLSTRIP 3 & 4	No	No	No	Yes
COPCO 1 & 2	No	No	Yes	Yes
CRAIG 1 & 2	No	No	No	Yes
CURRANT CREEK	Yes	Yes	Yes	Yes
DAVE JOHNSTON 1	No	No	Yes	Yes
DAVE JOHNSTON 2	No	No	Yes	Yes
DAVE JOHNSTON 3	No	No	Yes	Yes
DAVE JOHNSTON 4	Yes	Yes	Yes	Yes
FISH CREEK	No	No	No	Yes
GADSBY 1	No	No	Yes	Yes
GADSBY 2	No	No	Yes	Yes
GADSBY 3	Yes	Yes	Yes	Yes
GADSBY 4	Yes	Yes	Yes	Yes
GADSBY 5	Yes	Yes	Yes	Yes
GADSBY 6	Yes	Yes	Yes	Yes
HAYDEN 1 & 2	No	No	No	Yes
HERMISTON 1	Yes	Yes	Yes	Yes
HERMISTON 2	Yes	Yes	Yes	Yes
HUNTER 1	Yes	Yes	Yes	Yes
HUNTER 2	Yes	Yes	Yes	Yes
HUNTER 3	Yes	Yes	Yes	Yes
HUNTINGTON 1	Yes	Yes	Yes	Yes
HUNTINGTON 2	Yes	Yes	Yes	Yes
JC BOYLE	No	No	No	Yes
JIM BRIDGER 1	Yes	Yes	Yes	Yes
JIM BRIDGER 2	Yes	Yes	Yes	Yes
JIM BRIDGER 3	Yes	Yes	Yes	Yes
JIM BRIDGER 4	Yes	Yes	Yes	Yes
LAKE SIDE	Yes	Yes	Yes	Yes
LEMOLO	No	No	No	Yes
LITTLE MOUNTAIN	No	No	No	Yes
MERWIN	No	No	No	Yes
MID-COLUMBIA	Yes	Yes	Yes	Yes
NAUGHTON 1	No	No	Yes	Yes
NAUGHTON 2	Yes	Yes	Yes	Yes
NAUGHTON 3	Yes	Yes	Yes	Yes
SWIFT	Yes	Yes	Yes	Yes
TOKETEE-SLIDE	No	No	No	Yes
WYODAK	Yes	Yes	Yes	Yes
YALE	Yes	Yes	Yes	Yes

3.3.6 Modeling gas plant utilization in PaR

One of the objectives in calculating wind integration costs using PaR was to emulate observed real-time unit commitment and dispatch behavior of PacifiCorp's thermal plants during the simulation period. A specific focus was placed on east-side gas plants capable of providing regulation reserve service. The commitment status of these gas plants, consisting of Currant Creek, Lake Side, and Gadsby units 4 through 6, was initially set to "must run" in PaR to mirror recent utilization of these units. In the PaR framework, must run status means that the unit is committed, but not necessarily fully dispatched, at all times. PacifiCorp then compared the resulting simulated capacity factors for the simulation year 2013 against actual plant capacity factors for 2009 keeping in mind that 2009 wind generation and load data are used as inputs for the 2013 PaR simulation year. Differences in the capacity factors were reasonably small.

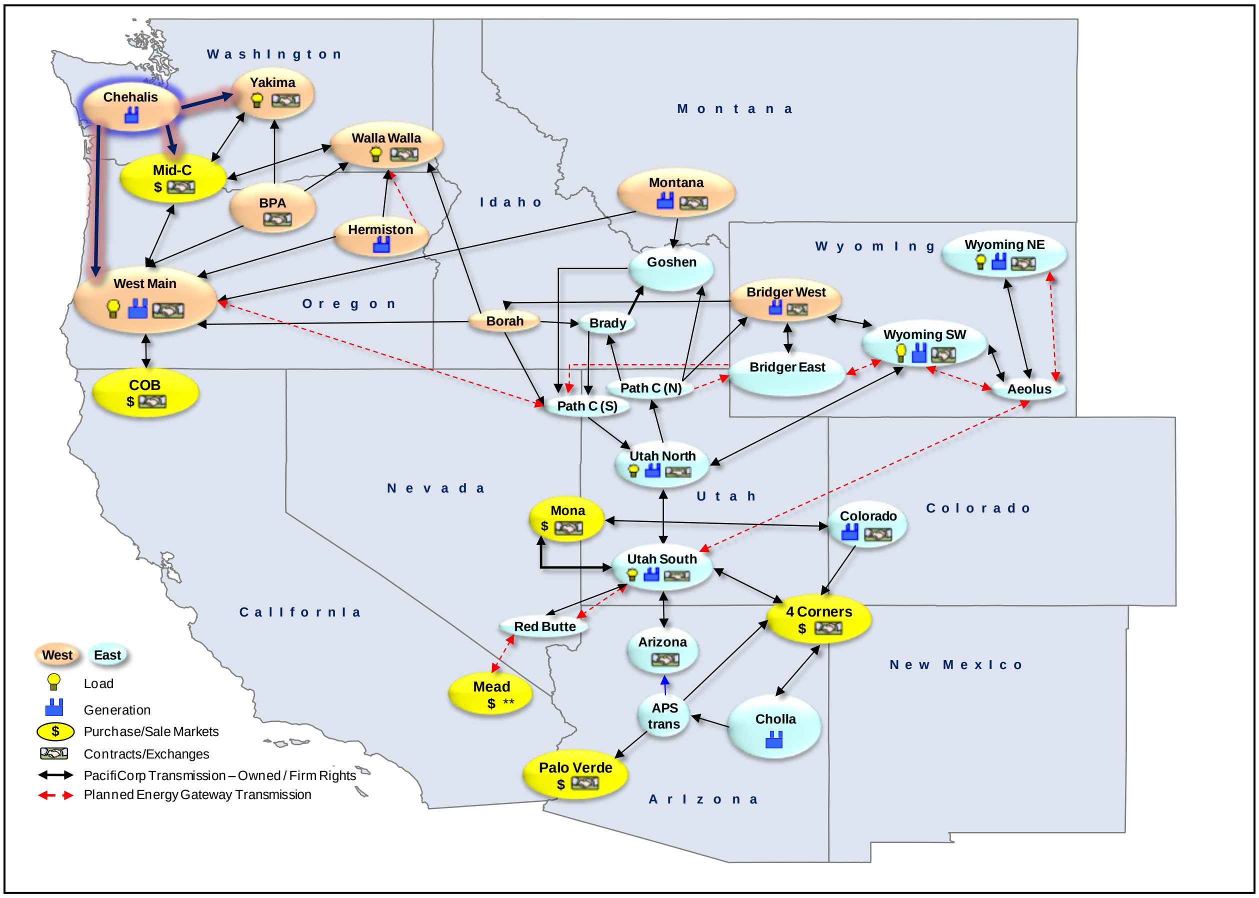
Given these findings, PacifiCorp concluded that PaR was reasonably aligned with actual operational characteristics of the east-side gas plants when setting Current Creek and Gadsby units 4 through 6 as must run. Consequently, this must run configuration was applied in PaR to circumvent the fact that PaR establishes unit commitment on price and not necessarily on operating reserve requirements. In this way, and consistent with recent operational practice, the Current Creek and Gadsby units 4 through 6 are available for meeting operating reserve obligations even when out-of-the-money from a pure market dispatch perspective.

The must run setting on Currant Creek and Gadsby units 4 through six was applied in PaR Simulations 2 through 4. In each of these simulations, incremental operating reserve demand needed to integrate wind is applied in the model, and must-run configuration ensures that the select set of east-side gas units will be available to meet the added reserve obligation even at times when they are out-of-the-money. In contrast, PaR Simulation 1 does not include any incremental operating reserve demand, and thus, the must-run setting was not used.

3.3.7 Transmission Topology in PaR

PacifiCorp used the PaR transmission topology consistent with the 2008 IRP Update as shown in Figure 13.

Figure 13. PaR transmission topology.



3.3.8 Carbon Dioxide Cost Assumptions in PaR

Given the 2011 to 2013 forward term used in the Study, there was no CO_2 cost applied to fossil-fired thermal generating resources. This assumption simplifies any comparison of the calculated wind integration cost among the three forward simulation years and avoids the possibility of disparity between plant dispatch costs and wholesale electricity market forward prices used over the term. This is in contrast to the 2008 IRP Update, in which PacifiCorp assumed that federal cap and trade carbon dioxide (CO_2) allowance prices go into effect in 2013, with prices starting at $8.58/ton in 2013 dollars and escalating at 1.8 percent per year thereafter.

4. Results

4.1 Operating Reserve Demand

Based upon historical and simulated wind generation data and historical load data, the Study shows that operating reserve demand for both regulation reserve service and load following reserve service increases with higher wind penetration levels. Table 11 summarizes how operating reserve demand for both regulation and load following services increases as wind penetration levels grow from approximately 425 MW to approximately 1,833 MW.

Table 11. Annual average operating reserve demand by penetration scenario.

		Load Only	425 MW	1372 MW	1833 MW
West	Regulation Up	97	105	137	137
	Regulation Down	72	84	120	120
	Load Following Up	101	114	139	141
	Load Following Down	106	113	132	133
East	Regulation Up	138	140	201	231
	Regulation Down	107	110	185	222
	Load Following Up	139	144	207	245
	Load Following Down	144	147	198	237

The increase in operating reserve necessary to support wind generation in grid operations is apparent in each of the penetration scenarios. For example, very little wind generation is added to the East Balancing Authority Area between the load-only and 425 MW scenarios, and understandably, there is little increase in the resultant incremental operating reserve demand. The same situation occurs between the 1,372 MW and 1,833 MW penetration scenarios on the West Balancing Authority Area, where again, there is little change to the calculated operating reserve demand. Additionally, as significant wind generation development impacts the East Balancing Authority Area between the 425 MW and 1,372 MW scenarios, and again between the 1,372 MW and 1,833 MW scenarios, there is clearly a proportionate growth of the operating reserve required to satisfy higher levels of wind penetration.

Tabular monthly results for each Balancing Authority Area and for each type of reserve service appear in Appendix C. For convenience, Figures 14 through 21 summarize monthly operating reserve demand results. In reviewing these figures, it is helpful to compare the growth of estimated reserve demand per MW of wind penetration recognizing that most of the wind capacity in the 425 MW penetration scenario is in the West Balancing Authority Area and that most of the incremental wind capacity in the 1,372 and 1,833 MW penetration scenarios is in the East Balancing Authority Area.

Figure 14. Load following up operating reserve service demand in the West Balancing Authority Area.

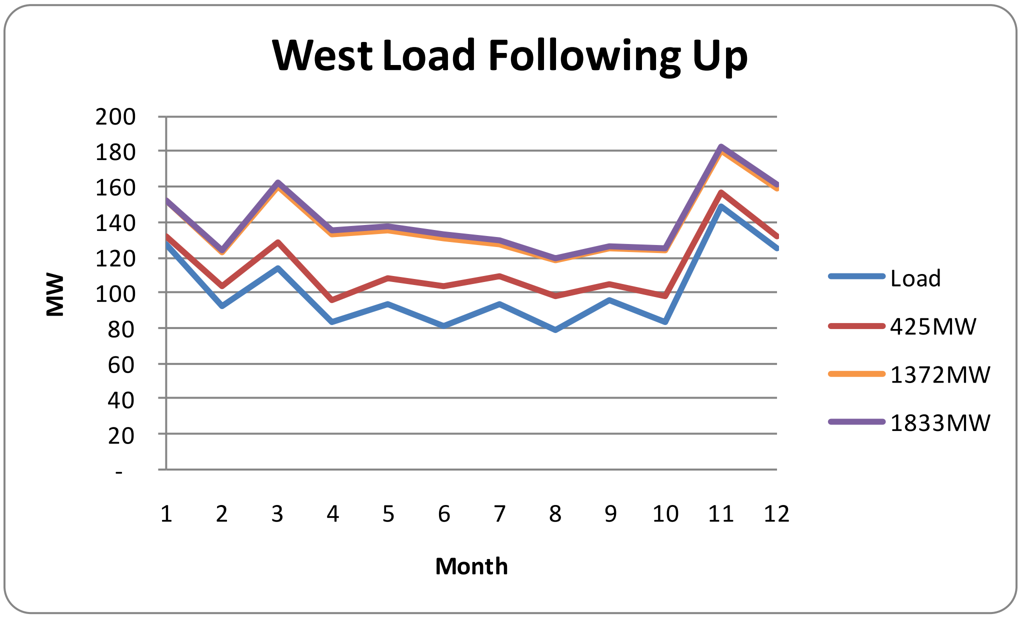


Figure 15. Load following down operating reserve service demand in the West Balancing Authority Area.

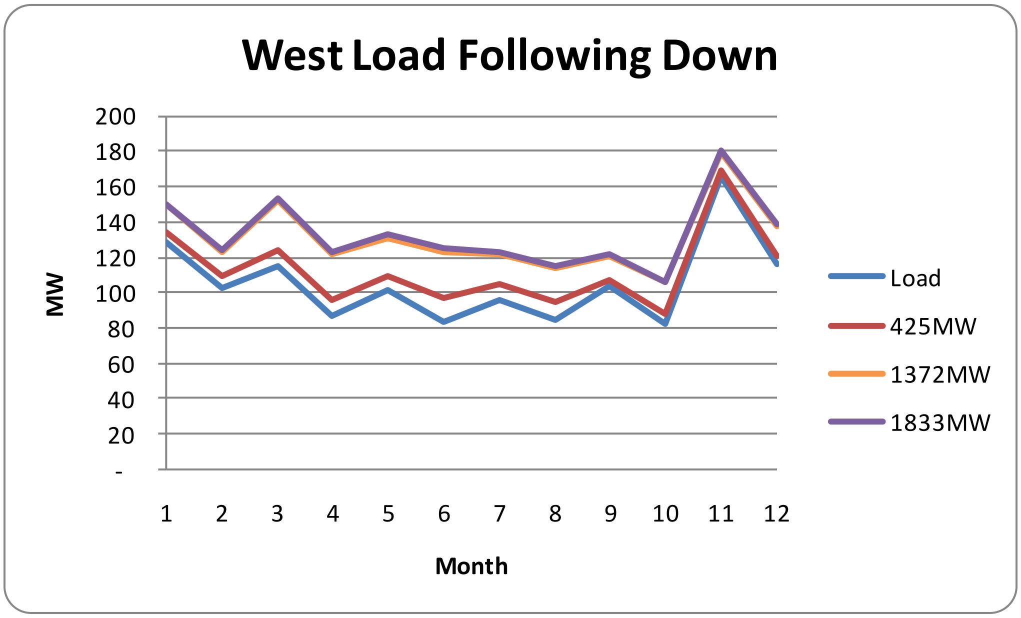


Figure 16. Regulation up operating reserve service demand in the West Balancing Authority Area.

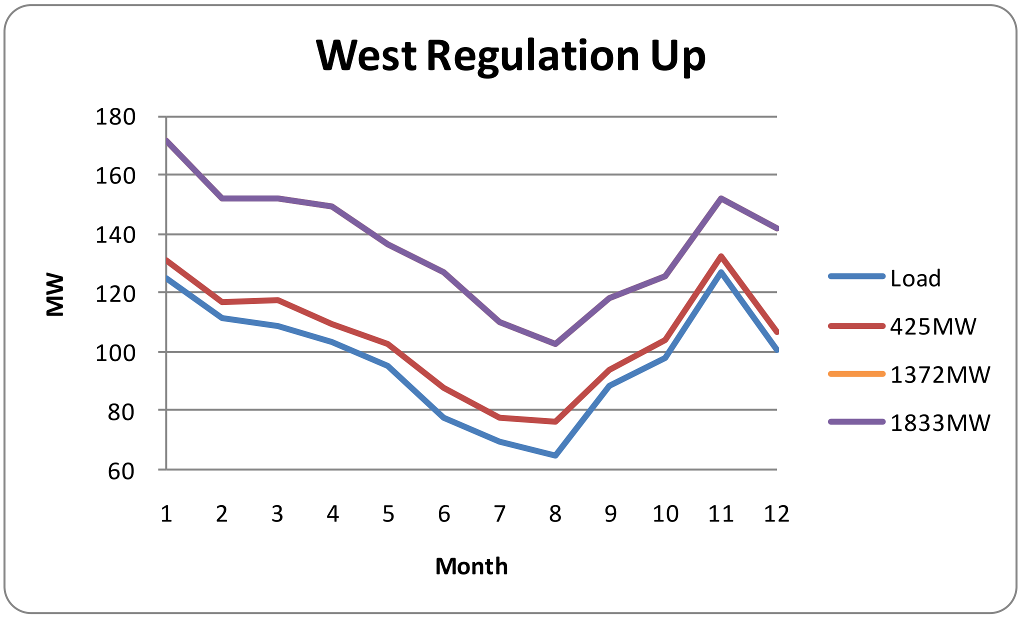


Figure 17. Regulation down operating reserve service demand in the West Balancing Authority Area.

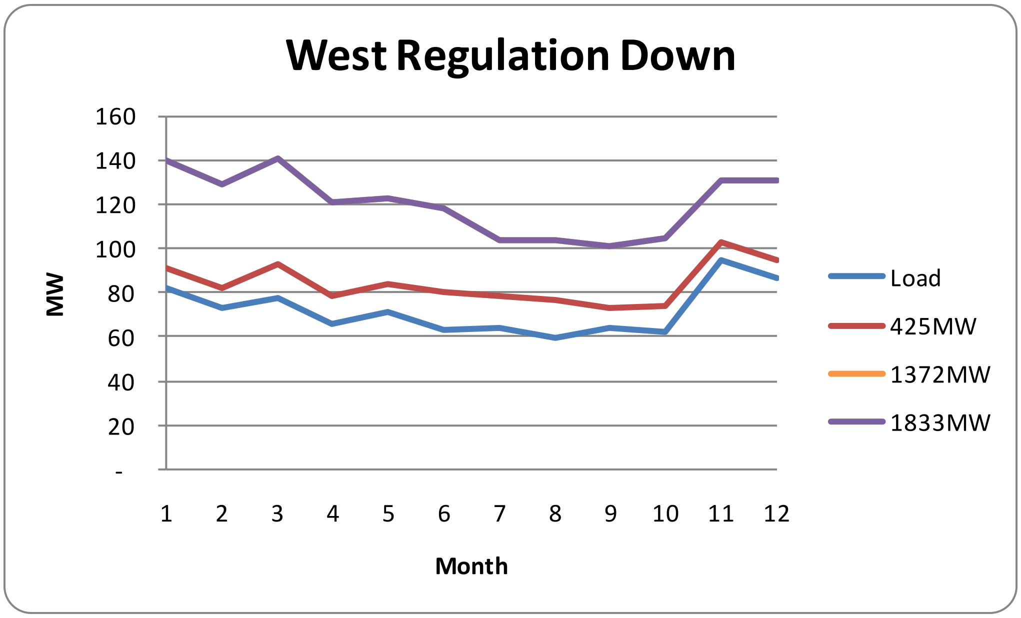


Figure 18. Load following up operating reserve service demand in the East Balancing Authority Area.

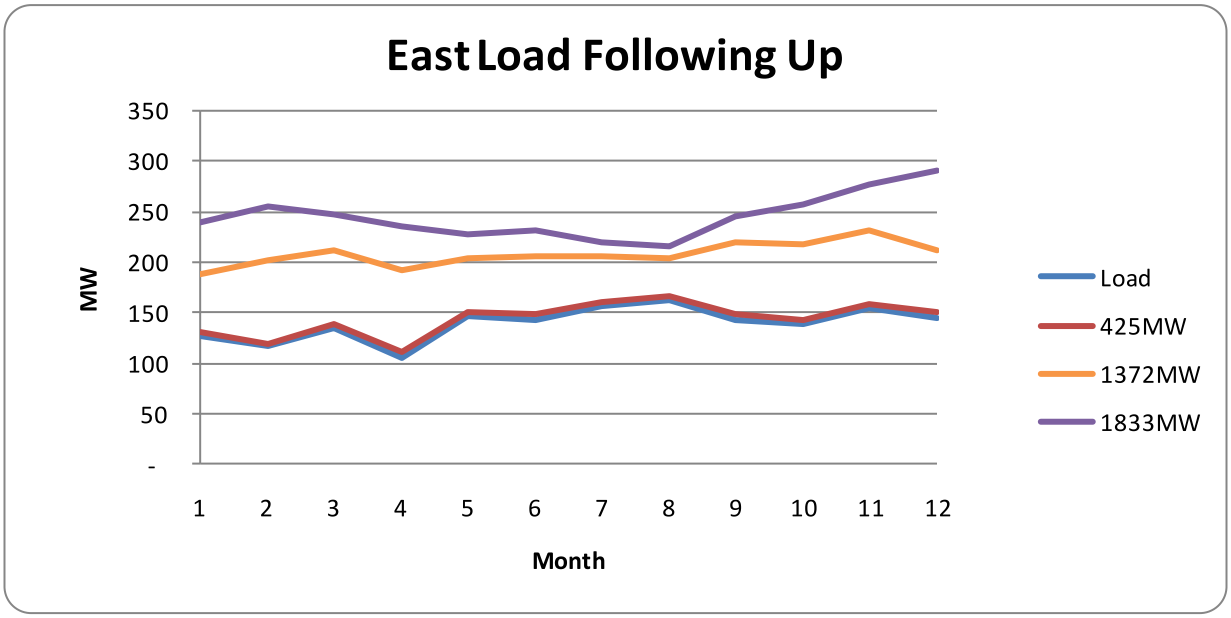


Figure 19. Load following down operating reserve service demand in the East Balancing Authority Area.

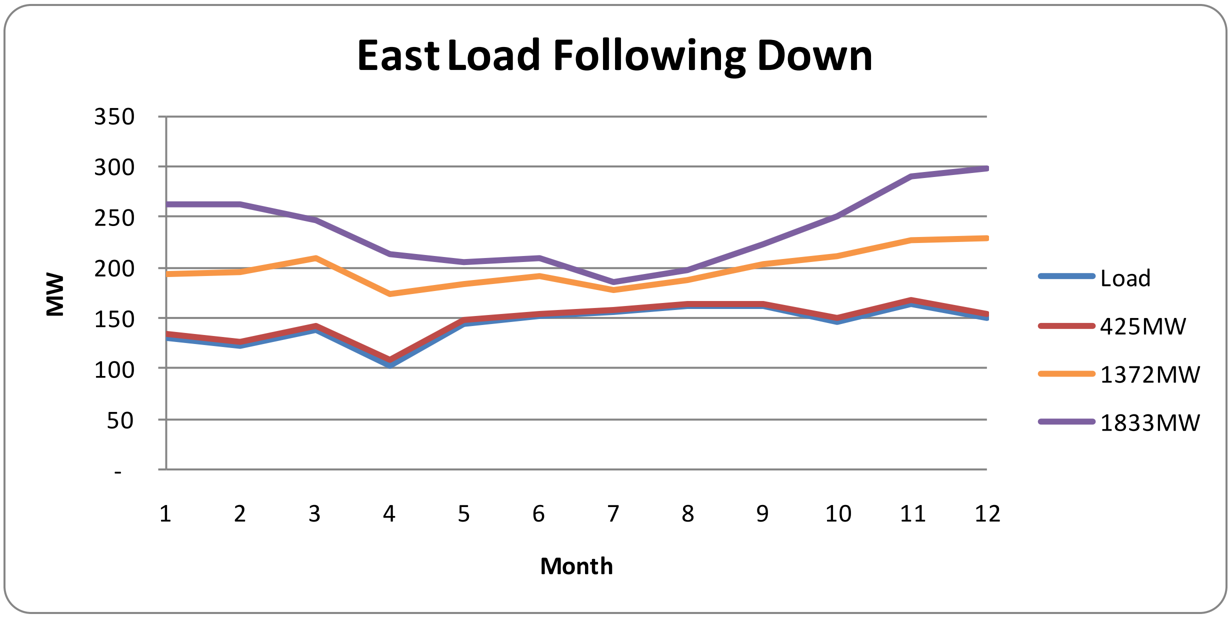


Figure 20. Regulation up operating reserve service demand in the East Balancing Authority Area.

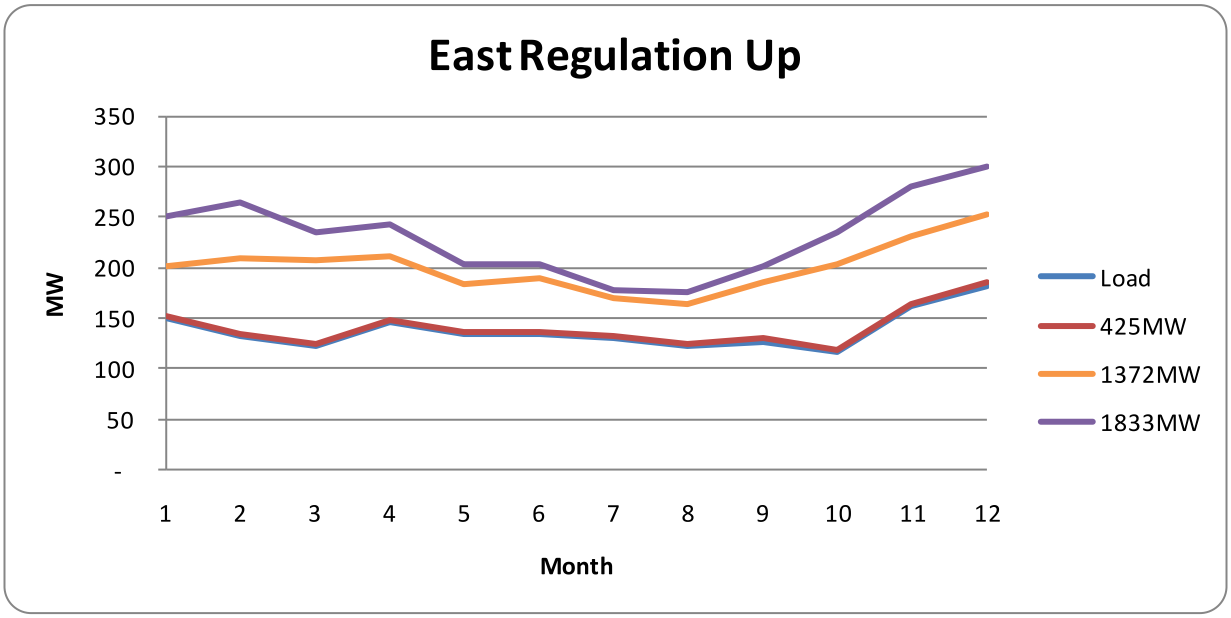
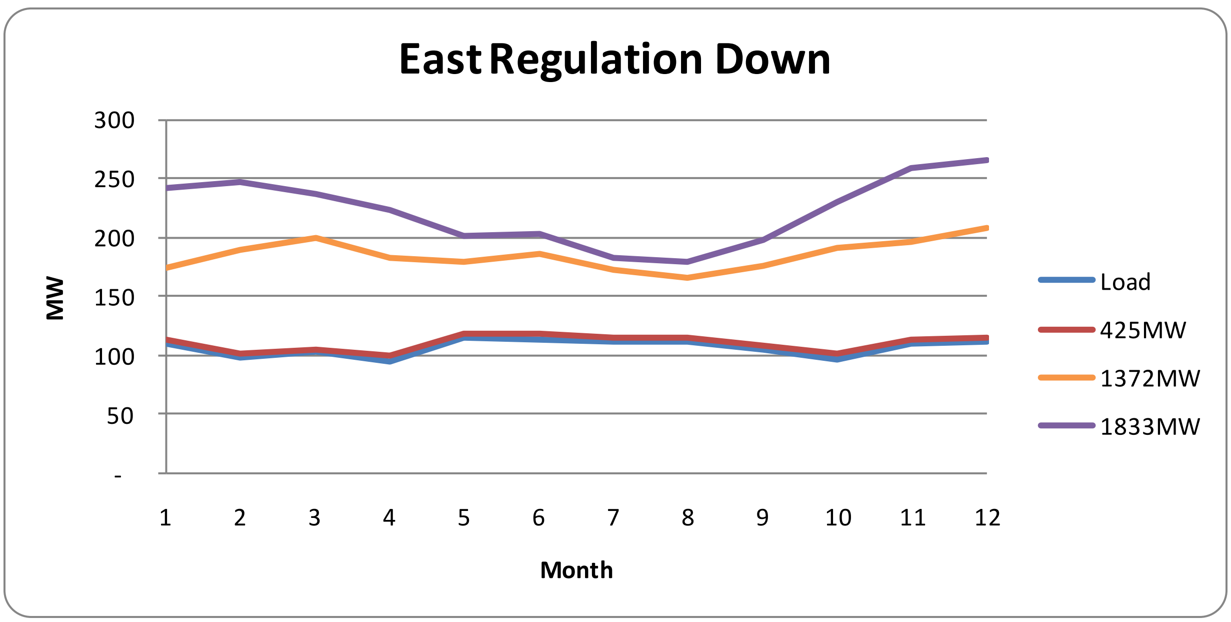


Figure 21. Regulation down operating reserve service demand in the East Balancing Authority Area.



Figures 14 through 21 identify both the seasonal nature of the operating reserve required to cover wind integration services and the tendency for the services' demand to be increased in months where more wind energy is generated. The monthly variation in operating reserve demand is built into the costing of the services in PaR, considering that the allocation of operating reserve for wind generation is less in the months where there is less need.

4.2 Wind Integration Costs

Tables 12 and 13 present the wind integration cost results for each wind penetration scenario. Costs are reported in both present value revenue requirement (PVRR) dollars and dollars per megawatt-hour of wind generation for each year in the study period. Levelized costs across the three year study term are also included in the far right column of each scenario table.

Table 12. PaR simulation results for the load only scenario and the 425 MW wind penetration scenario.

		Load Only				425 MW			
Total variable costs		**2011**	**2012**	**2013**	**Levelized**	**2011**	**2012**	**2013**	**Levelized**
Base (No Wind)	thousands	$ 1,192,794	$ 1,311,178	$ 1,301,577		$ 1,192,794	$ 1,311,178	$ 1,301,577	
Simulation 1		$ 1,192,794	$ 1,311,178	$ 1,301,577		$ 1,141,308	$ 1,251,695	$ 1,249,391	
Simulation 2		N/A	N/A	N/A		$ 1,150,552	$ 1,261,783	$ 1,259,733	
Simulation 3		$ 1,188,903	$ 1,300,920	$ 1,286,758		$ 1,145,876	$ 1,251,190	$ 1,241,733	
Simulation 4		$ 1,201,530	$ 1,322,377	$ 1,313,055		$ 1,152,348	$ 1,264,907	$ 1,264,277	
Calculation of Integration Costs									
Operating Reserve (Sim 2 less Sim 1)	thousands	$ -	$ -	$ -	$ -	$ 9,244	$ 10,088	$ 10,342	$ 25,830
System Balancing (Sim 4 less Sim 2)		$ -	$ -	$ -	$ -	$ 1,796	$ 3,124	$ 4,544	$ 8,094
Total	thousands	$ -	$ -	$ -	$ -	$ 11,040	$ 13,212	$ 14,886	$ 33,924
Wind Generation (Actual)									
East Wind	GWh	-	-	-	-	534	603	520	1,446
West Wind		-	-	-	-	754	794	665	1,937
Total	GWh	-	-	-	-	1,288	1,396	1,185	3,383
Operating Reserve	**$/MWh**	**$ -**	**$ -**	**$ -**	$ -	**$ 7.18**	**$ 7.22**	**$ 8.73**	$ 7.64
System Balancing		**$ -**	**$ -**	**$ -**	$ -	**$ 1.39**	**$ 2.24**	**$ 3.83**	$ 2.39
Total Wind Integration	**$/MWh**	**$ -**	**$ -**	**$ -**	$ -	**$ 8.57**	**$ 9.46**	**$ 12.56**	$ 10.03

Table 13. PaR simulation results for the 1,372 MW and 1,833 MW wind penetration scenarios.

		1400 MW				1750 MW			
Total variable costs		**2011**	**2012**	**2013**	**Levelized**	**2011**	**2012**	**2013**	**Levelized**
Base (No Wind)	thousands	$ 1,192,794	$ 1,311,178	$ 1,301,577		$ 1,192,794	$ 1,311,178	$ 1,301,577	
Simulation 1		$ 1,046,895	$ 1,141,572	$ 1,148,139		$ 1,014,831	$ 1,103,397	$ 1,112,343	
Simulation 2		$ 1,075,215	$ 1,172,782	$ 1,180,728		$ 1,053,713	$ 1,145,954	$ 1,156,774	
Simulation 3		$ 1,080,733	$ 1,179,114	$ 1,176,686		$ 1,068,866	$ 1,163,768	$ 1,163,482	
Simulation 4		$ 1,077,117	$ 1,175,126	$ 1,186,073		$ 1,057,087	$ 1,149,484	$ 1,162,164	
Calculation of Integration Costs									
Operating Reserve (Sim 2 less Sim 1)	thousands	$ 28,320	$ 31,210	$ 32,589	$ 80,135	$ 38,882	$ 42,557	$ 44,431	$ 109,512
System Balancing (Sim 4 less Sim 2)		$ 1,902	$ 2,344	$ 5,345	$ 8,165	$ 3,374	$ 3,530	$ 5,390	$ 10,609
Total	thousands	$ 30,222	$ 33,554	$ 37,934	$ 88,300	$ 42,256	$ 46,087	$ 49,821	$ 120,121
Wind Generation (Actual)									
East Wind	GWh	2,319	2,520	2,232	6,175	3,230	3,483	3,106	8,576
West Wind		1,462	1,556	1,332	3,805	1,462	1,556	1,332	3,805
Total	GWh	3,781	4,076	3,564	9,980	4,692	5,040	4,438	12,380
Operating Reserve	**$/MWh**	**$ 7.49**	**$ 7.66**	**$ 9.14**	$ 8.03	**$ 8.29**	**$ 8.44**	**$ 10.01**	$ 8.85
System Balancing		**$ 0.50**	**$ 0.58**	**$ 1.50**	$ 0.82	**$ 0.72**	**$ 0.70**	**$ 1.21**	$ 0.86
Total Wind Integration	**$/MWh**	**$ 7.99**	**$ 8.23**	**$ 10.64**	$ 8.85	**$ 9.01**	**$ 9.14**	**$ 11.23**	$ 9.70

The PaR model results demonstrate interesting trends in the component costs. Most notable is the reduction of system balancing costs for the 1,372 MW and 1,833 MW wind capacity penetration scenarios when compared to the 425 MW wind capacity penetration scenario. This is due to the domination of load forecast error in the 425 MW scenario system balancing integration cost line item, where total system costs are divided by wind energy production to derive system costs on a per unit of wind generation basis. The system balancing costs stabilize as wind generation increases in the higher penetration scenarios. Additionally, the operating reserve integration costs increase with additional wind capacity penetration. The rate of increase in costs is outpacing the increased wind energy produced, resulting in a higher price per megawatt-hour of wind energy produced. Finally, it is noteworthy that the addition of wind generation capacity lowers overall system costs.

Table 14 compares the results of the Study to integration costs developed for the 2008 IRP on a component by component basis using Levelized costs over the applicable terms. The primary differences in results are most apparent for inter-hour (2008 IRP)/system balancing (2010 Study) wind integration costs. This difference is explained by improvements in method. In the 2008 IRP, market transaction costs were used to estimate inter-hour integration costs, whereas the current Study calculates system balancing integration costs derived from the operation of PacifiCorp resources.

Table 14. Wind integration cost comparison to the 2008 IRP.

Study	2008 IRP	2010 Wind Integration Study	2010 Wind Integration Study
Wind Capacity Penetration	2734 MW	1372 MW	1833 MW
Tenor of Cost	20-Year Levelized	3-Year Levelized	3-Year Levelized
Expected to Day Ahead ($/MWh)	$0.28	-	-
Day Ahead to Hour Ahead ($/MWh)	$2.17	-	-
System Balancing ($/MWh)	-	$0.82	$0.86
Subtotal Interhour / System Balancing	$2.45	$0.82	$0.86
Intra Hour Reserves[1] ($/MWh)	$7.51		
2010 Study Operating Reserves ($/MWh)		$8.03	$8.85
Total Wind Integration	**$9.96**	**$8.85**	**$9.70**
Assumptions			
Forward Price Curve	Oct 2008, $8CO2	Mar 2010, No CO2	Mar 2010, No CO2

1 - IRP resources were available to meet Operating Reserve demand before the in-service year, which lowers wind integration cost

4.3 Application of Wind Integration Costs in the 2011 Integrated Resource Plan

The start of portfolio development for PacifiCorp's 2011 IRP is scheduled for September 2010. Portfolio development relies on the Company's capacity expansion optimization model, called System Optimizer. (Note that wind integration impacts are treated as an increased resource cost in the System Optimizer model.) The high-end wind capacity penetration scenario will not be completed until after portfolio development is well underway. Until costs are assessed for the high-end wind capacity penetration scenario, PacifiCorp will use the costs developed for the 1,833 MW penetrations scenario, totaling $9.70/MWh of wind generated power.

Appendix A

Simulation of Wind Generation Data

A.1 Detailed Discussion of Statistical Patterns of the Historical Wind Output Data

From the available ten-minute interval historical wind generation data over the 2007 to 2009 Initial Term, there are four key observations. First, wind output has a seasonal pattern. Taking one plant as an example, Figure 1A shows capacity factor data for Leaning Juniper in 2009. The red markers in the figure indicate the median of the distribution, and the wide bar delineates the 25th to 75th percentiles of the distribution. Figure 1A shows the median, as well as the range of observed capacity factors in each month in 2009 for Leaning Juniper varies significantly. Second, the monthly standard deviations for capacity factor output are very different across sites in most months. Figure 2A compares the output patterns across June, July, and August of 2009 for Leaning Juniper and Combine Hills and shows that non-normality is evident in the data. Again, the red markers indicate the median of the distribution, and the wide bar represents the 25th to 75th percentiles in the distribution. Third, the commonly-accepted notion that wind output follows a pronounced diurnal pattern is only partially supported by the various historical profiles in the dataset, as apparent in Figure 3A. In general, such recurring patterns are more easily found in average aggregate representations of the data on hourly level, rather than by examining higher resolution ten-minute data.

Figure 1A. Leaning Juniper 2009 monthly capacity factors.

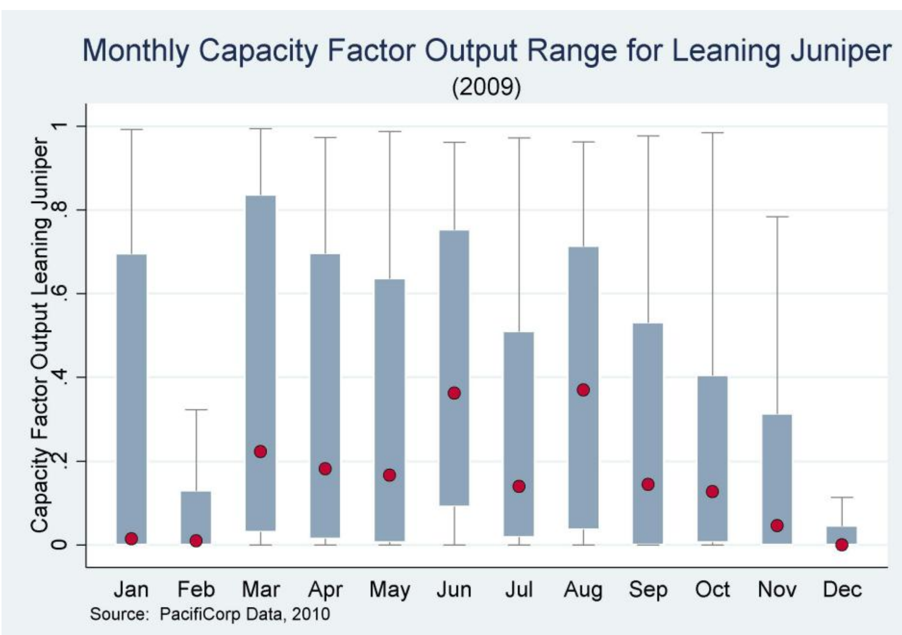


Figure 2A. Comparison of Leaning Juniper and Combine Hills capacity factors.

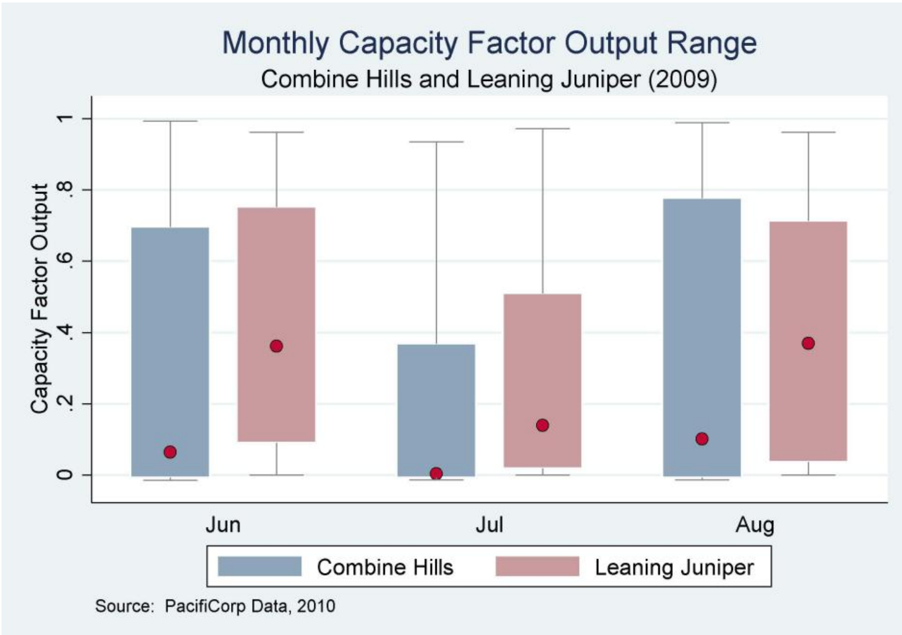
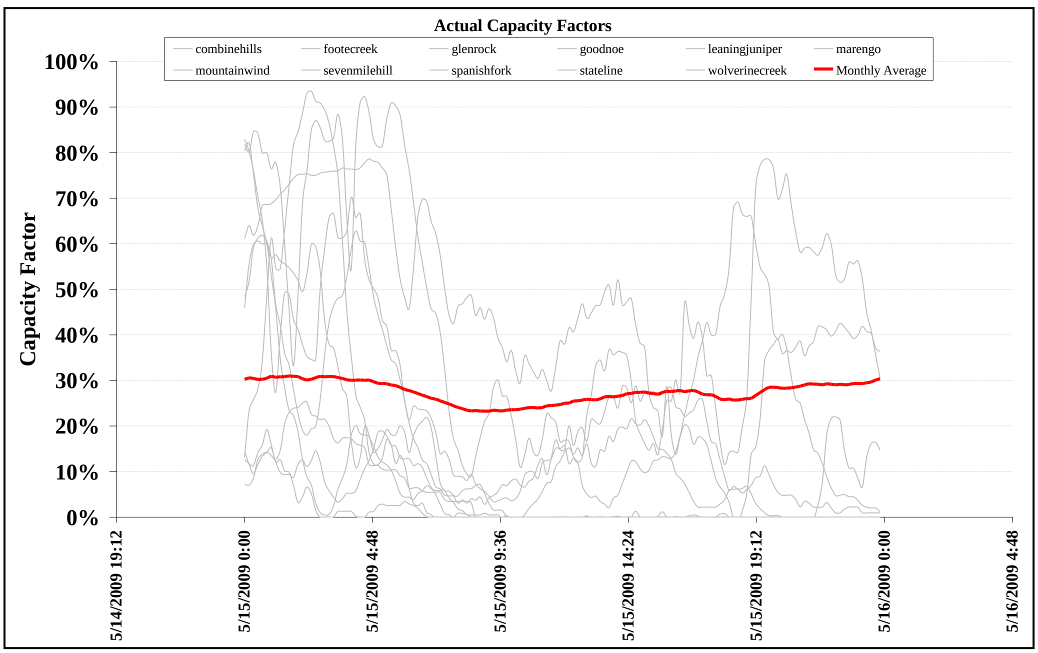


Figure 3A. Daily generation patterns of several PacifiCorp wind plants.



Finally, Figures 4A and 5A present the empirical distribution of the 2009 capacity factor output of Leaning Juniper and Combine Hills, respectively. Both plants' hourly capacity factor data represent two key patterns to the study. One, that there are a very substantial number of zero generation hours for each station. Two, the output varies greatly through the potential capacity range of each generating station, implying the wind generation will have the characteristic to vary from one time period to the next. This is different behavior than would be implied by a strong bimodal diurnal pattern, which would imply very regular on/off behavior with and without wind.

Figure 4A. Distribution of observed 2009 hourly capacity factors at Leaning Juniper.

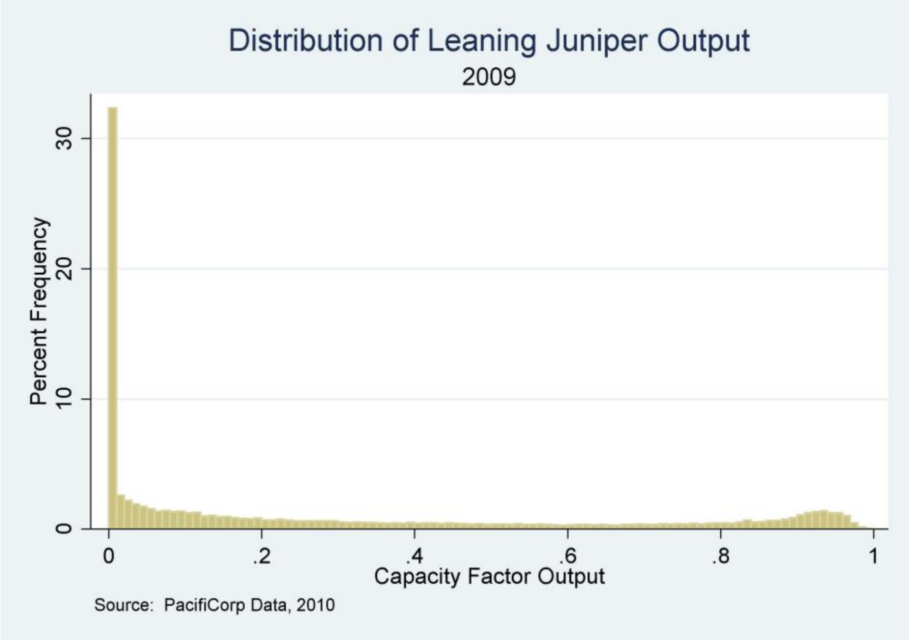
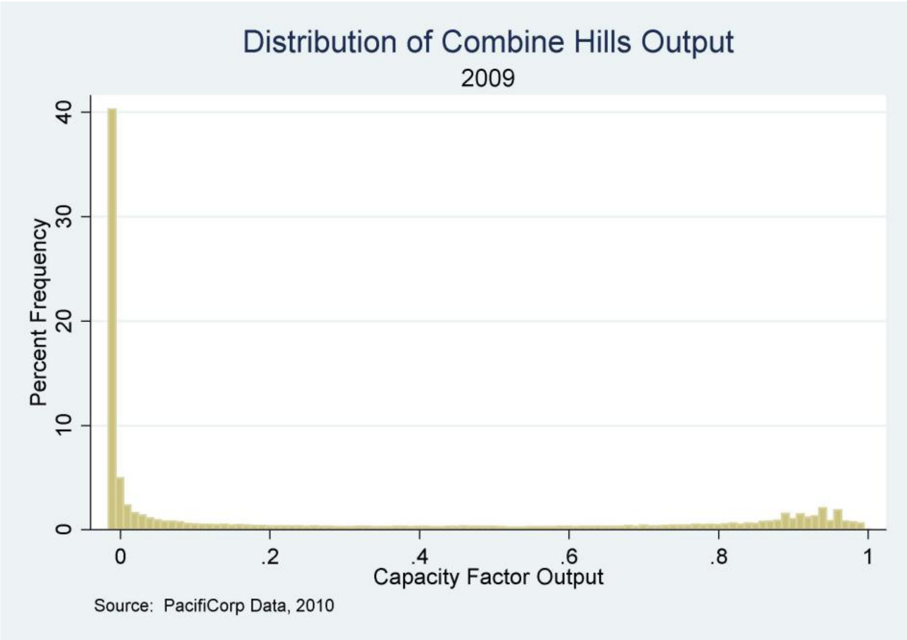


Figure 5A. Distribution of observed 2009 hourly capacity factors at Combine Hills.



A.2 Time Pattern of the Historical Wind Data

The time-series properties of the wind generation data are also important to the Study. Initial data analysis revealed that the wind generation profiles in the dataset were consistently characterized by a slowly decaying auto correlation process, while their partial autocorrelations are significant up to 6 period lags. In other words, the wind data in a ten-minute period is heavily consistent with the previous 10-minute interval and, therefore, over time, the wind pattern could be described as influenced by its behavior in the previous time periods. Partial correlation measures the autocorrelation at a specific lagged time frame, while controlling for the effect of preceding lags. Partial autocorrelation is useful in determining the number of lagged terms to include as explanatory variables in a regression model. Figures 6A through 9A show the full and partial auto correlation factors for the Leaning Juniper and Combine Hills wind plants. Figures 6A and 7A show that the predictive power fades regularly over time lag. Figures 8A and 9A show that the oscillating nature of wind generation is more apparent in the negative predictive power of the 2nd and 4th lags.

Figure 6A. Autocorrelation coefficients for successive ten minute lags in capacity factor for Leaning Juniper.

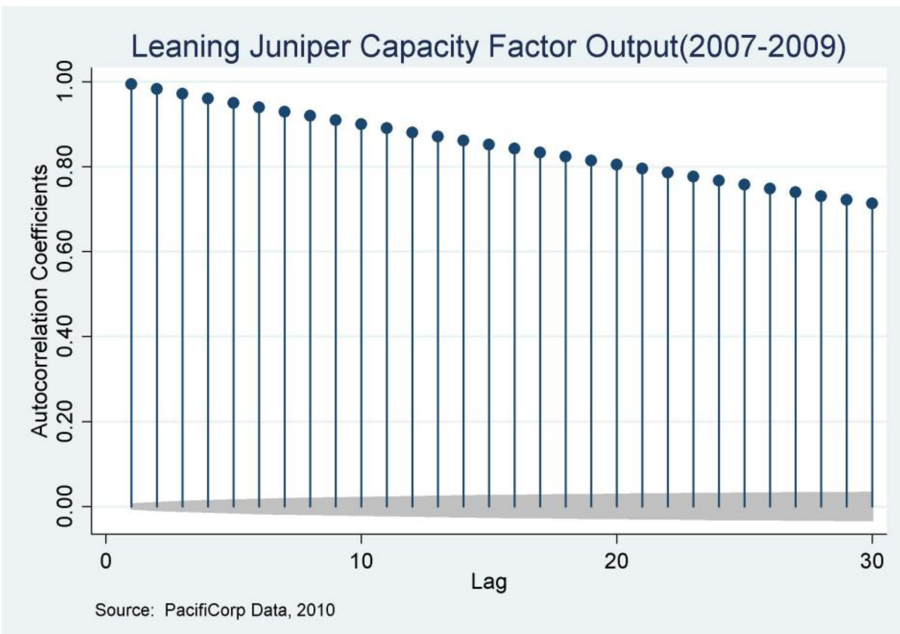


Figure 7A. Autocorrelation coefficients for successive ten minute lags in capacity factor for Combine Hills.

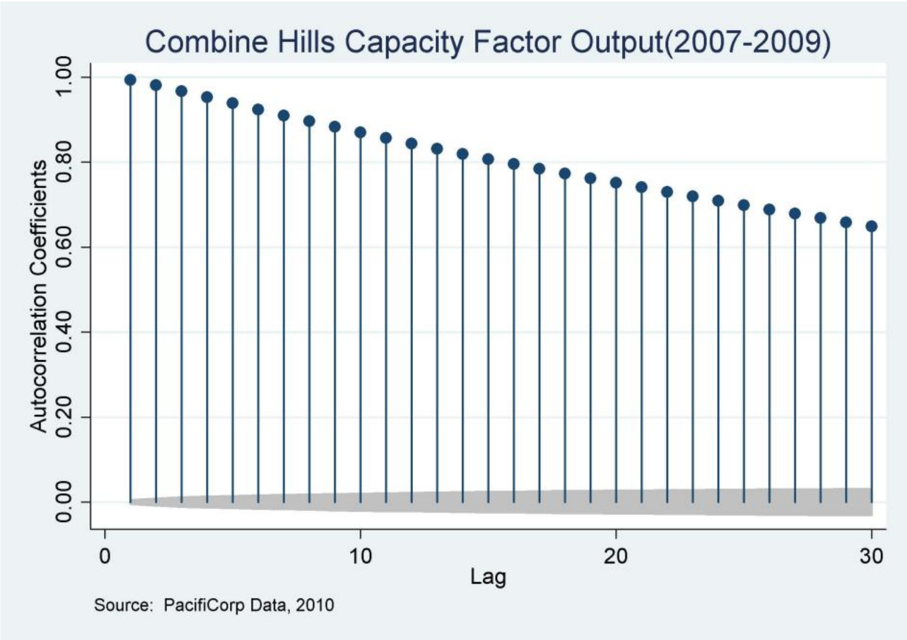


Figure 8A. Partial autocorrelation coefficients for lags in capacity factor for Leaning Juniper.

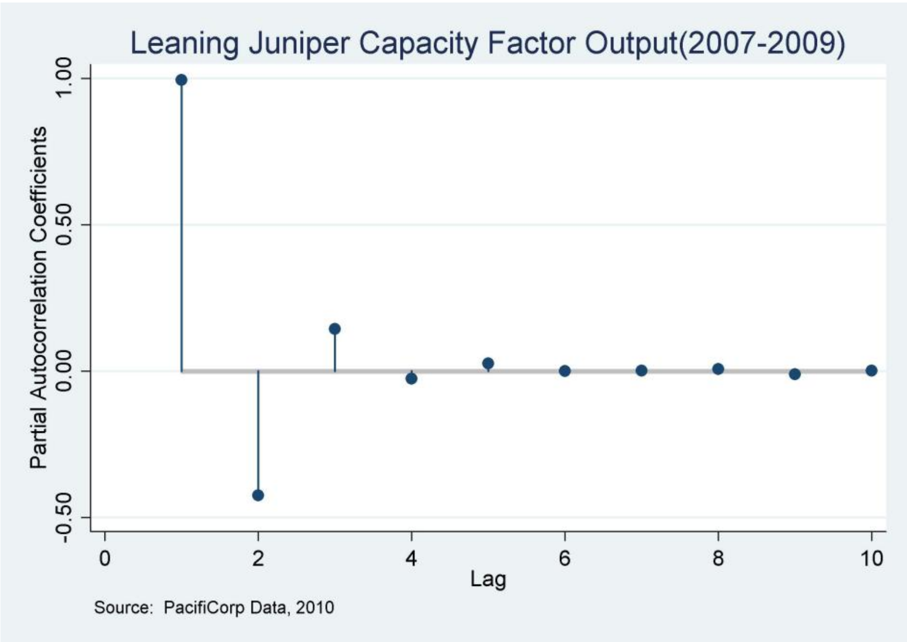
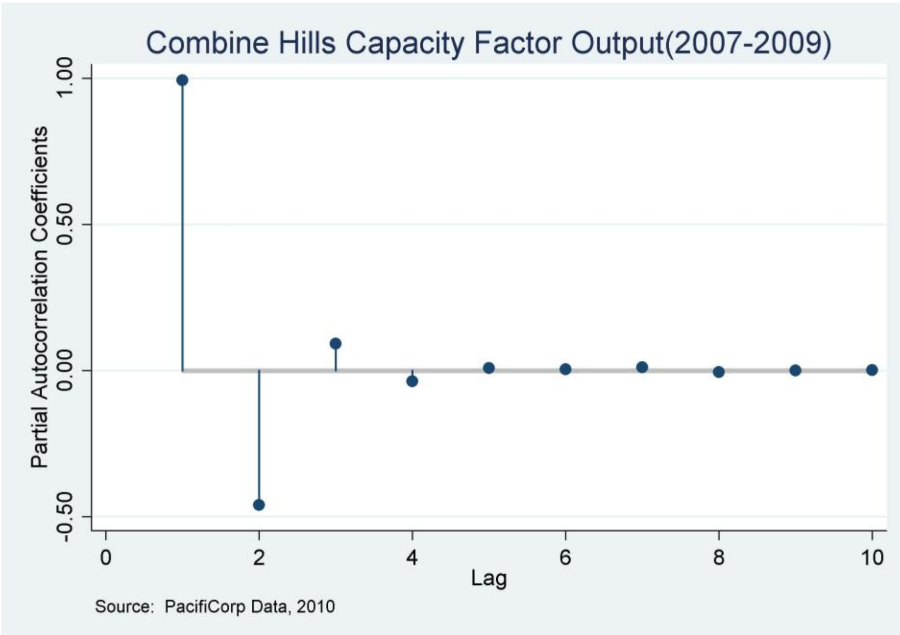


Figure 9A. Partial autocorrelation coefficients for lags in capacity factor for Combine Hills.



A.3 Data Clean-up and Verification

The source wind generation data were characterized by a number of issues that needed data clean-up, verification and, in some cases, adjustments. The first observed issue is that for certain records over various periods of time, the historical wind output data were zero. Those observations covered varying lengths of time and, in some instances, up to a few months. However, we noticed that the zero-value data blocks consistently occurred only at the beginning of a wind project's chronological energy output data and therefore it is suspected that those were probably periods when the plant had not yet been fully commissioned. Thus, those observations are treated as "missing" and excluded them from the historical data set.

Next, through our source data review, we identified that the output of certain plants seemed to have much smaller capacity factors and increased over time. This trend seemed to have extended beyond the natural volatility of wind generation for those wind sites and showed up as a gradual increase over time and reaching a maximum after a number of months. This observation seemed to suggest that the historical data were capturing the build-out of a wind site before it has reached its commercial operation date. As the maximum available capability through wind plant construction on a daily basis was not documented, the decision was made to exclude wind output data for dates prior to the known commercial operation date for each wind site. As a result, the data set used for simulations was limited to include only date ranges that conform to the known commercial operation dates shown in Table 1A.

Table 1A. Summary of wind plant start dates and nameplate capacity.

Plant name	Applied Commercial Operation Date	Nominal Capacity (MW)	Observed Max Output (MW)
Dunlap I	11/1/2010	111	Data Unavailable
Goodnoe Hills	5/31/2008	94	95
Glenrock	1/17/2009	237	232
Glenrock III			
Rolling Hills			
High Plains	9/13/2009	99	148
McFadden Ridge I	10/10/2009	29	29
Leaning Juniper	9/14/2006	101	103
Marengo I	6/26/2008	211	206
Marengo II			
Seven Mile Hill I	12/31/2008	119	123
Seven Mile Hill II			
Combine Hills	6/17/2003	41	41
Wolverine Creek	4/29/2005	65	65
Mountain Wind I	9/29/2008	141	137
Mountain Wind II			
Three Buttes	12/1/2009	99	Data Unavailable
Top of the World	12/31/2010	202	Data Unavailable
Spanish Fork	7/31/2008	19	22
Foote Creek I	4/1/1999	95	137
Foote Creek II			
Foote Creek III			
Foote Creek IV			
Rock River			

The sites that were affected by these revisions were:

- Goodnoe Hills (observations were set to missing for November 2007 through May 2008),
- Marengo (observations were set to missing for February 2007 through May 2008),
- Spanish Fork (observations were set to missing for April 2008 through Jul 2008),
- Mountain Wind (observations were set to missing for April 2008 through September 2008),
- Seven Mile Hill (observation were set to missing for November 2008 through December 2008),
- McFadden Ridge (observations were set to missing for June 2009 through September 2009),
- High Plains (observations were set to missing for February 2009 through August 2009),
- Glenrock (observations were set to missing for November 2008 through December 2008).

- That leaves five wind sites that were not affected by this adjustment —Leaning Juniper, Combine Hills, Stateline, Wolverine Creek, and Foote Creek.

The second clean-up process involved understanding the aggregation of data and the interpretation of the plant size. The data provided to the technical advisor contained single wind output data stream for sites that share the same principal name but are distinguished as individual projects—those include Marengo and Marengo II, Mountain Wind and Mountain Wind II, Seven Mile Hill and Seven Mile Hill II, Glenrock and Glenrock III. The wind output data, which were collected on-site, did not distinguish between separate sharing the same name.

The third clean-up involved the fact that the maximum output levels observed in the wind output data sometimes exceed the capacity officially available to PacifiCorp. The Study team decided to use the maximum output found in each wind profile data stream to be the *de facto* wind site megawatt capacity. We used this capacity level and converted each 10-minute output into a capacity factor value ranging from 0 to 1.[28]

A.4 Wind Data Simulation Methodology

A.4.1 General Description

The overall methodology centered on using available data to estimate the missing data. To do so, the statistical relationships between pairs of sites were studied and those relationships were used to derive or estimate the wind output for periods that historical data are incomplete or missing. For example, if there was a *fully available* set of historical data for site A, but *partially missing* for site B, the overlapping periods during which historical data are available for both sites A and B were used to estimate the statistical relationship using that data. Then the technical advisor employed that statistical relationship and used the available data from site A for the period when site B has missing data to estimate wind data for that period. If site B has *completely missing* data, the technical advisor applied NREL's simulated data (from 2004-2007) to establish the statistical relationship between sites A and B and then applied that estimated relationship to the historical data of site A and again, estimated site B's wind output accordingly.

A.4.2 Wind Generation Estimation Model Specification

In general, the modeling approach is based on the use of contemporaneously available ten-minute wind capacity factor data from *fully available* wind profiles to simulate capacity factor data for profiles with *partially* or *completely missing* wind output. As prior figures demonstrated, ten-minute wind output exhibited a generally volatile profile with several notable features. First, output from previous periods is highly indicative of the current level of output, with the partial autocorrelations significant up to as many as six lags. Second, the diurnal patterns were harder to discern on a consistent basis. Given these characteristics and our preliminary analysis, we chose to include six lagged terms in addition to the concurrent wind output term in the model used to estimate the statistical relationship between pairs of sites. We have found that such

[28] The capacity factor represents the output at a given point in time as a fraction of the maximum possible output for the wind project. For example, a capacity factor of 0.23 indicates that current output is 23% of the total capacity of the wind site.

specification allows us to capture the time-based behavior and time-dependence of the wind data used in the Study. This approach also captures some of the spatial relationship between the two sites—as wind moves from one site to the other, its impact on the other site is delayed in time. The equation below describes the general structure of the model[29]:

$$Site_t^A = \alpha_0 Site_t^B + \alpha_1 Site_{t-1}^B + \alpha_2 Site_{t-2}^B + \alpha_3 Site_{t-3}^B + \alpha_4 Site_{t-4}^B + \alpha_5 Site_{t-5}^B + \alpha_6 Site_{t-6}^B + \varepsilon$$

A.4.3 Wind Generation Estimation Model for Constrained Output

An important challenge in specifying this model is the nature of the capacity factor variables. Capacity factor is used instead of absolute wind output levels to translate between small and large wind plants. By such a construction, the wind output measured in capacity factor terms can only take values between 0 and 1 (or, equivalently 0% and 100%). Attempting to predict a limited dependent variable using a standard linear ordinary least squares (OLS) approach resulted in estimated values for the dependent variable (or sites with *partially missing* and *completely missing* historical data) that are outside the possible value range.

For example, for given mean values of the explanatory variables, the linear OLS model might result in a predicted mean dependent variable value greater than a capacity factor of 100%. This is due to the fact that a linear OLS model does not limit the outcome range for the dependent variable. In the literature, a model whose dependent variable is limited at either one or both upper and lower ends of its range is called a "censored" model.[30] A standard approach for estimating a censored model is to use the *Tobit* regression model. The *Tobit* model was originally developed by James Tobin (1958)[31] and employs an estimation technique, which recognizes the limited ("censored") range of possible values that the *observed* dependent variable can take.[32] As a result, predicted mean values for the dependent variable will behave as expected and not exceed the natural capacity limits of 0 and 1, as specified in our case.

The *Tobit* model uses a maximum likelihood process, which takes into account the probability of obtaining an observation that lies inside the censoring interval. In other words, *Tobit* typically is used to estimate the likelihood of a value to be equal to some expected quantity. The model assumes that the true value of the dependent variable (y*) is explained by a number of independent variables, where the regression error term (epsilon) is normally distributed with a zero mean. In addition, if y* is between 0 and 1 we observe y*, however, if y*<0 we observe 0 and, similarly, if y*>1, we observe 1. The maximum likelihood estimation uses the probability of each individual observation being censored to estimate the regression coefficients.[33] In other words, the regression coefficients are determined to ensure that their value maximizes the likelihood of obtaining the observed values of y*.[34]

[29] We specify a regression model that has no constant term.

[30] Greene, William H., "Econometric Analysis", 5th Ed., Prentice Hall 2003, p. 764.

[31] Gujarati, Damodar N., "Basic Econometrics", McGraw Hill 2003, p. 616; Kennedy, Peter "A Guide to Econometrics," 5th Ed., MIT Press 2003, pp. 289-290.

[32] Ibid.

[33] For example, see "STATA Base Reference Manual Release 11", Stata Corp. pp. 1939-1948; Maddala, G. S., "Limited-Dependent and Qualitative Variables in Econometrics.", Cambridge University Press 1986, pp.159-162.

[34] For more detailed description of the Tobit model, please see Maddala, G. S., "Limited-Dependent and Qualitative Variables in Econometrics", Cambridge University Press 1986, pp.159-162.

In contrast to linear OLS regression, the *Tobit* regression model does not report an R-squared metric, which typically indicates the explanatory power of the regression model specification (with high R-squared value indicating stronger explanatory power). In other words, in the linear OLS regression, the adjusted R-squared measures the proportion of variance of the dependent variable that has been explained by the independent (right-hand-side) variables. There are a range of so-called "Pseudo R-Squared" metrics that have been proposed in the literature for use with maximum likelihood models, such as the *Tobit* model. However, their interpretation is not equivalent to the R-Squared in OLS. This is because estimates derived using a *Tobit* model are calculated via an iterative process designed to maximize the likelihood of obtaining the observations of the dependent variable, rather than to minimize variance.[35]

The technical advisor used the statistical software package STATA© to perform the regressions using the Tobit model. The model specification uses the chosen explanatory variables and generates a censored prediction of y* where the relevant upper and lower censoring limits are taken into account.[36] An example of the six-lag model the technical advisor settled upon for significance is below:

$$Goodnoe_t^A = \alpha_0 LeaningJuniper_t^B + \alpha_1 LeaningJuniper_{t-1}^B + \alpha_2 LeaningJuniper_{t-2}^B + \\ + \alpha_3 LeaningJuniper_{t-3}^B + \alpha_4 LeaningJuniper_{t-4}^B + \alpha_5 LeaningJuniper_{t-5}^B + \alpha_6 LeaningJuniper_{t-6}^B + \varepsilon$$

A.4.4 Using NREL's Wind Data to Facilitate Wind Simulation for Sites without Historical Information

To simulate wind data of sites with no historical information, the technical advisor used the NREL wind data to estimate the statistical relationship between pairs of sites and then used the estimated relationship to simulate the necessary wind data. For sites with *completely missing* historical wind data, NREL sites are chosen to serve as a proxy wind profiles.

NREL's *Western Wind Dataset* was created by *3TIER* for use in NREL's *Western Wind and Solar Integration Study*. The dataset was synthesized using numerical weather prediction (NWP) models "to recreate the historical weather for the western U.S. for 2004, 2005, and 2006. The modeled data were temporally sampled every 10 minutes and spatially sampled every arc-minute (approximately 2 kilometers)."[37] We refer to this wind data set as the "NREL data".

The first step in using the NREL *Western Wind Dataset* is to identify NREL-modeled sites that are the closest in geographical terms to the relevant PacifiCorp wind sites. These are called the "NREL proxies" for each corresponding PacifiCorp wind site. The technical advisor then estimated the statistical relationship between the pairs of NREL proxies (that correspond to PacifiCorp wind sites) and used the statistical relationship to carry out the rest of the simulation

[35] For more information, please see: Long, J. Scott. "Regression Models for Categorical and Limited Dependent Variables" Thousand Oaks: Sage Publications, 1997; Freese, Jeremy and J. Scott Long. "Regression Models for Categorical Dependent Variables Using Stata", College Station: Stata Press, 2006.
[36] For more information, please see: Baum, Christopher F., "An Introduction to Modern Econometrics Using Stata", College Station: Stata Press, 2006, p. 264.
[37] http://www.nrel.gov/wind/integrationdatasets/western/methodology.html#methodology [accessed July 1, 2010]

described above. PacifiCorp staff provided the technical advisor with the geographical coordinates (latitude and longitude) for the PacifiCorp wind sites as summarized in Table 2A. In addition, the NREL data contains comprehensive information on the geographical coordinates of all modeled sites.[38] The technical advisor then determined the closest NREL proxy for each of plant.[39]

Table 2A. NREL Proxies selected for pertinent PacifiCorp plants.

PacifiCorp Plant Name	Closest NREL Site ID	Distance (km)
High Plains	16676	0.5
McFadden	16676	0.5
Rock River	31422	0.4
Rolling Hills	23909	2.9
Dunlap	19280	0.8
Three Buttes	23870	5.3
Top of the World	23803	4.8

Table 2A shows each PacifiCorp-NREL pair and the calculated distance between them. We should note that High Plains and McFadden Ridge share the same geographical location and, as a result, are paired with the same NREL-modeled site. As a result, High Plains and McFadden Ridge have identical simulated profiles. (This is a function of the study's approach of simulating wind generation output based on geographical location rather than wind project name—for example, the same simulated profile is also used to represent the Mountain Wind/Mountain Wind II pair of wind sites.)

After determining the set of NREL sites to be used in the simulation analysis, NREL data were formatted, compiled by site, and labeled using their PacifiCorp counterpart's name. Similar to the earlier approach in formatting the PacifiCorp data, NREL wind output data were converted into capacity factor terms (using a 30 MW capacity value for each site as specified in the NREL description of the dataset).[40]

[38] The main web portal for the NREL Western Wind Dataset can be accessed at http://wind.nrel.gov/Web_nrel
[39] Geographical coordinates for two points on the earth's surface can be converted to a straight-line distance using a range of alternative algorithms, which take into consideration the shape of the earth and use trigonometric formulas to project and measure surface distances. For the purposes of this study, the Spherical Law of Cosines was used to calculate the distance between each relevant PacifiCorp wind site and every site in the Western Wind Dataset. Fore more information, please see: Weisstein, Eric W. "Spherical Trigonometry." From MathWorld -- A Wolfram Web Resource. http://mathworld.wolfram.com/SphericalTrigonometry.html [accessed July 1, 2010]

Distance (km) = ArcCos(Sin(Latitude Pacificorp) * Sin(Latitude NREL) + Cos(Latitude Pacificorp) * Cos(Latitude NREL) * Cos(Longitude NREL - Longitude Pacificorp)) * 6371 km

[40] http://www.nrel.gov/wind/integrationdatasets/about.html [accessed July 1, 2010]

A.4.5 Pairing of Wind Profiles Used for Regression

Recognizing the monthly seasonality of wind data, each modeled pair required twelve separate regression models per year, one for each month.[41] To ensure the use of observed historical wind data is meaningful, we require that a full year of overlap between a *fully available* wind profile and a *partially missing* wind profile. This means that if the *partially missing* wind profile only had 11 months of historical data, it was treated as a *completely missing* dataset and used the NREL data to help simulate the data from the period without historical data. To simplify the rest of this explanation, the *fully available* wind profile was a *predictor* and a site with *partially missing or completely missing* wind profile was a *predicted* site (because the process effectively used the available profile to "predict" the missing profile).

The Study focused on two methods in estimating monthly regressions. First, for sites with *partially missing* historical wind data that have at least 12 months of historical data, the data from a *fully available* site was employed as the *predictor* (such as Foote Creek, Combine Hills, or Leaning Juniper) to estimate monthly coefficients. From the coefficients derived in the regression estimation, the Study estimated the wind data for all the missing months. Second, for sites with *partially missing* data (and with less than 12 months historical data available) and sites with *completely missing* data, the NREL *closest neighbor* set of wind profiles was employed. The process estimated monthly regression models between the closest NREL site to the *predictor* and the closest NREL site to the *predicted*. Then the coefficients estimated in those regressions were applied to the PacifiCorp *fully available predictor* data to simulate 10-minute output data for the *predicted.* This second approach implicitly assumed that the monthly relationships between the *predictor* and the *predicted* derived from the 2004-2006 period (using available NREL data) were applicable to the Initial Term as represented by the PacifiCorp data.
Below in Figure 10A, a flow chart depicts the steps described above. Table 3A depicts the pairs of wind sites with left column containing the *predictor* and the right column containing the *predicted.*

[41] For example, if overlapping data for the *predictor* and the *predicted* are available for all of 2008 and 2009, we estimate a regression for January using data for that month from both 2008 and 2009. Then, the estimated coefficients from the regression will be used to predict the output for January of 2007 using the *predictor* 2007 data for that month.

Figure 10A. Wind generation data development flow chart.

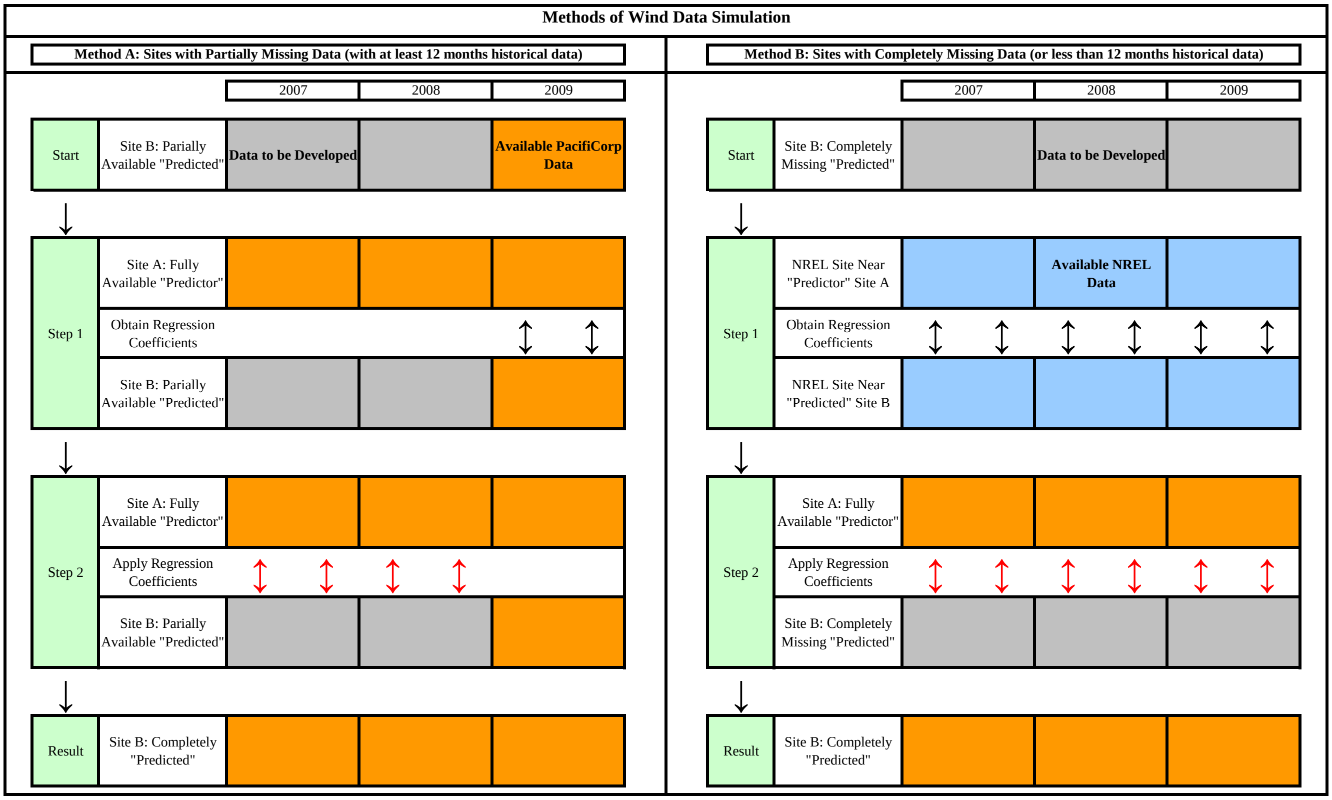


Table 3A. Pairs of wind projects used in data simulation.

Predicted	Predictor	Data Used
High Plains	Foote Creek	NREL/PacifiCorp
McFadden	Foote Creek	NREL/PacifiCorp
Rock River	Foote Creek	NREL/PacifiCorp
Rolling Hills	Foote Creek	NREL/PacifiCorp
Dunlap	Foote Creek	NREL/PacifiCorp
Three Buttes	Foote Creek	NREL/PacifiCorp
Top of the World	Foote Creek	NREL/PacifiCorp
Goodnoe	Leaning Juniper	PacifiCorp
Marengo	Combine Hills	PacifiCorp
Mountain Wind	Foote Creek	PacifiCorp
Seven Mile Hill	Foote Creek	PacifiCorp
Spanish Fork	Foote Creek	PacifiCorp
Glenrock	Foote Creek	PacifiCorp

A.4.6 Regression Analysis

The estimation process of the *Tobit* regressions was identical across all sites—the six-lag model is applied to a *predictor-predicted* pair. After estimation, the resulting coefficients were used to generate data for the *predicted* profile for all missing time periods using the values of the *predictor* in those time periods.[42] A sample of resulting regression coefficients for one month for one pair of wind sites is shown in Table 4A below.

Table 4A. Predictive capacity factor coefficients for the simulation of Goodnoe Hills wind generation using Leaning Juniper actual generation data.

Explanatory Variables	Estimated Coefficients
Capacity Factor Leaning Juniper	0.841***
	(0.0744)
Capacity Factor Leaning Juniper [t-1]	-0.321**
	(0.130)
Capacity Factor Leaning Juniper [t-2]	0.0314
	(0.135)
Capacity Factor Leaning Juniper [t-3]	0.0631
	(0.135)
Capacity Factor Leaning Juniper [t-4]	0.0597
	(0.135)
Capacity Factor Leaning Juniper [t-5]	0.00342
	(0.130)
Capacity Factor Leaning Juniper [t-6]	0.267***
	(0.0744)
Observations	4,464

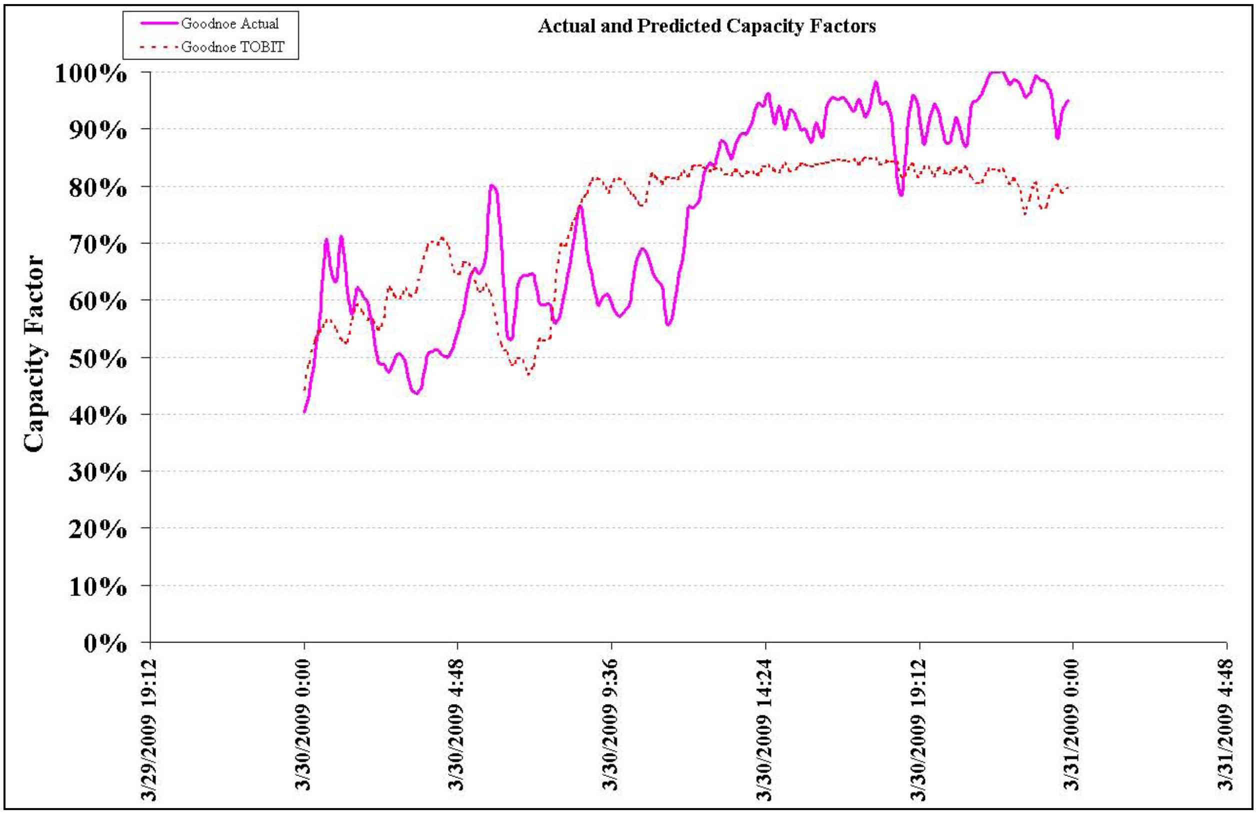
Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

A.4.7 Estimate Mean Values of the Predicted

In general, using the estimated regression coefficients to derive a prediction for the dependent variable is done by using the mean values of the explanatory variables to arrive at the predicted mean value of the dependent variable. In this case, however, we are interested in generating predicted values of the dependent variable (*predicted)* for all individually observed values of the independent variable (*predictor*). As a result, applying the estimated regression coefficients to each individual observation of the explanatory variables will result in predicted values of the *predicted* that are significantly less variable than the true unobserved *predicted* series. This is due to the fact that the regression model assumes that the regression error is zero on average across the observations, but not in every individual instance. An illustrative comparison of the predicted mean value to the historical actual of the same period is shown in Figure 11A.

[42] Again, all estimation procedures and simulations were conducted using the commercially-available statistical software package STATA© (http://www.stata.com)

Figure 11A. Comparison of actual Goodnoe Hills capacity factors with predicted mean Goodnoe Hills capacity factors derived off of Leaning Juniper generation data.



A.4.8 Calculating the Regression Residuals

To address the loss of variability by simply using the regression coefficients in the estimation, the technical advisor subtracted the predicted values of the dependent variable from their corresponding observed values over the overlapping subset of *predicted/predictor* data used for the regression estimation.[43] This produced a set of regression residuals, which represent the amount by which predicted values for the known (historical) part of the data set were different from the actual observed values of the *predicted.*

Then, each regression residual value was categorized according to the level of predicted output it was originally associated with. The predicted values are then grouped in bins of 10 percentage points to create 10 bins that cover the range of 0% to 100% capacity factor output. For example, all residuals that were associated with a predicted output between 10% and 20% are grouped together. As Figures 12A and 13A show, the distributions of those residuals vary across bins.

[43] In the case of the PacifiCorp sourced data, this is done over the monthly regression data. For the Hybrid approach where NREL data was required, this is done with the NREL data.

Figure 12A. Highly non-normal residuals from bin 5 of the March regression of Goodnoe Hills capacity factor derived from observed Leaning Juniper data.

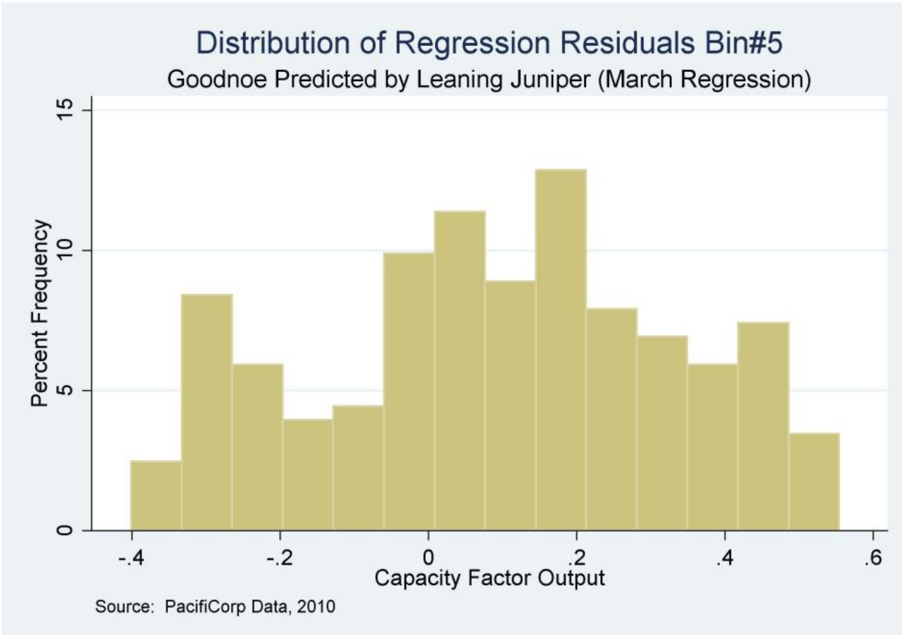


Figure 13A. Highly non-normal residuals from bin 7 of the March regression of Goodnoe Hills capacity factor derived from observed Leaning Juniper data.

A.4.9 Sample of Residuals According to Simulated Output Ranges

The next step involved randomly drawing residuals from the previously defined bins and "adding them back" to the simulated mean 10-minute wind output. The procedure of making random draws from an empirical distribution of residuals is called "bootstrapping" residuals.[44] In the context of this study, the technical advisor applied the bootstrapping procedure by randomly drawing[45] a residual from a corresponding bin and adding it to the predicted mean capacity factor value. For example, if a predicted capacity factor value for a missing data point falls within the 10% to 20% interval, a residual value will be randomly drawn from the bin that contains the residuals of the corresponding capacity factor of the historical data when compared with the simulated (or predicted) mean values.

A.4.10 Application of a Non-Linear 3-Step Median Smoother to the Sampled Residuals

After generating a time-series of bootstrapped residuals, the additional step of applying a non-linear smoother to the series, called the "span-3 median smoother" was taken. The span-3 median smoother is a process by which the median of the current, previous, and next period value — in this case, it is calculated by taking the median of residual(t-1), residual(t), residual(t+1)[46] — and using that median as the residual for the current period. The purpose of this approach is two-fold. Firstly, the median smoother ensures that the time-series of residuals resembles the time behavior of wind more closely, with lags affecting the instantaneous results. Secondly, the span-3 median smoother introduces a time-dependency to the data set, which is known to exist in the original wind data.[47]

The technical advisor then added the smoothed time-series of the randomly drawn residuals to the predicted mean capacity factor values for each ten-minute point; then checking the resulting data to make sure the estimates remained within the 0 – 100% capacity factor range.

[44] This name alludes to the fact that, absent prior knowledge of the distribution, the researcher has to pull herself by the bootstraps by drawing randomly from the empirically-derived residual data in order to generate residuals.
[45] Random draws are done with replacement as implemented by the STATA© *bsample* procedure.
[46] For example, see "STATA Base Reference Manual Release 11", Stata Corp. p. 1758; Mosteller, F. and Tukey, John W., "Data Analysis and Regression: A Second Course in Statistics", Addison-Wesley: 1977., pp. 52-58.
[47] Although the non-linear smoothing approach does not exactly replicate the auto-regressive behavior of the wind data, it introduces some similar dependency.

Appendix B

Regression Coefficients and Relative Significance

Regression Results by Month for Glenrock Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.347***	0.242	0.460**	0.278	0.0338	0.554***	0.105	0.576***	0.527***	0.597***	0.669***	0.594***
	(0.125)	*(0.160)*	*(0.184)*	*(0.193)*	*(0.181)*	*(0.140)*	*(0.124)*	*(0.104)*	*(0.140)*	*(0.160)*	*(0.160)*	*(0.168)*
Capacity Factor Foote Creek [t-1]	-0.161	-0.131	-0.186	-0.0782	-0.0667	-0.301	0.0168	-0.181	-0.157	-0.246	-0.310	-0.272
	(0.229)	*(0.288)*	*(0.309)*	*(0.334)*	*(0.298)*	*(0.259)*	*(0.209)*	*(0.174)*	*(0.234)*	*(0.283)*	*(0.283)*	*(0.298)*
Capacity Factor Foote Creek [t-2]	0.0830	0.0687	0.0658	0.0437	-0.0228	0.173	0.0738	0.0989	0.0445	0.154	0.126	0.0644
	(0.249)	*(0.304)*	*(0.322)*	*(0.349)*	*(0.306)*	*(0.283)*	*(0.218)*	*(0.182)*	*(0.241)*	*(0.301)*	*(0.299)*	*(0.313)*
Capacity Factor Foote Creek [t-3]	-0.000558	-0.0146	-0.0358	-0.0237	0.0461	0.00166	0.0998	0.0265	-0.0223	0.0128	-0.0828	-0.0207
	(0.252)	*(0.305)*	*(0.323)*	*(0.350)*	*(0.306)*	*(0.285)*	*(0.218)*	*(0.182)*	*(0.242)*	*(0.303)*	*(0.300)*	*(0.313)*
Capacity Factor Foote Creek [t-4]	0.00538	0.0916	0.0701	0.0163	0.0896	0.176	0.0423	0.0703	0.131	0.100	0.144	0.0531
	(0.249)	*(0.304)*	*(0.322)*	*(0.349)*	*(0.307)*	*(0.282)*	*(0.217)*	*(0.182)*	*(0.242)*	*(0.301)*	*(0.299)*	*(0.313)*
Capacity Factor Foote Creek [t-5]	-0.0399	-0.272	-0.0229	-0.0347	-0.121	-0.212	-0.132	-0.0851	-0.149	-0.275	-0.447	-0.280
	(0.229)	*(0.288)*	*(0.309)*	*(0.334)*	*(0.300)*	*(0.258)*	*(0.208)*	*(0.175)*	*(0.234)*	*(0.283)*	*(0.282)*	*(0.298)*
Capacity Factor Foote Creek [t-6]	0.126	0.561***	0.184	0.166	0.387**	0.405***	0.532***	0.245**	0.526***	0.538***	0.976***	0.710***
	(0.126)	*(0.160)*	*(0.184)*	*(0.193)*	*(0.182)*	*(0.140)*	*(0.123)*	*(0.104)*	*(0.140)*	*(0.160)*	*(0.160)*	*(0.169)*
Number of Observations	2,160	4,032	4,464	4,320	4,464	4,320	4,464	4,464	4,320	4,464	4,320	4,464

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Spanish Fork Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.360**	0.215	0.330	0.503**	0.200	0.0481	-0.0363	-0.183	0.259	0.379**	0.147	0.0538
	(0.175)	*(0.232)*	*(0.217)*	*(0.239)*	*(0.242)*	*(0.220)*	*(0.263)*	*(0.179)*	*(0.196)*	*(0.178)*	*(0.184)*	*(0.167)*
Capacity Factor Foote Creek [t-1]	-0.244	-0.184	-0.187	-0.181	-0.0632	-0.0647	-0.0745	0.0931	-0.0370	-0.103	-0.0451	-0.0854
	(0.328)	*(0.415)*	*(0.366)*	*(0.411)*	*(0.400)*	*(0.406)*	*(0.444)*	*(0.300)*	*(0.333)*	*(0.310)*	*(0.328)*	*(0.300)*
Capacity Factor Foote Creek [t-2]	0.0304	0.0212	0.119	0.0537	0.0487	0.0509	0.0109	0.00608	-0.0965	-0.0136	-0.00668	0.0305
	(0.357)	*(0.439)*	*(0.381)*	*(0.428)*	*(0.411)*	*(0.443)*	*(0.462)*	*(0.313)*	*(0.348)*	*(0.325)*	*(0.348)*	*(0.317)*
Capacity Factor Foote Creek [t-3]	0.0500	0.0332	-0.108	-0.0955	-0.0370	-0.0220	-0.115	-0.0282	0.0344	0.0905	-0.0276	-0.0956
	(0.361)	*(0.441)*	*(0.383)*	*(0.431)*	*(0.408)*	*(0.445)*	*(0.459)*	*(0.314)*	*(0.349)*	*(0.326)*	*(0.350)*	*(0.318)*
Capacity Factor Foote Creek [t-4]	-0.0474	0.0102	-0.00785	0.182	-0.0519	0.0244	0.113	-0.00375	-0.0545	-0.0824	0.0572	0.102
	(0.358)	*(0.440)*	*(0.382)*	*(0.430)*	*(0.407)*	*(0.440)*	*(0.458)*	*(0.312)*	*(0.348)*	*(0.325)*	*(0.349)*	*(0.317)*
Capacity Factor Foote Creek [t-5]	0.0972	-0.0666	0.00720	-0.323	0.0195	-0.111	0.00394	-0.0554	-0.115	0.0815	-0.215	-0.321
	(0.328)	*(0.416)*	*(0.367)*	*(0.412)*	*(0.404)*	*(0.402)*	*(0.440)*	*(0.298)*	*(0.333)*	*(0.310)*	*(0.329)*	*(0.300)*
Capacity Factor Foote Creek [t-6]	-0.128	0.199	-0.0310	0.0558	-0.152	0.0713	-0.00857	0.0280	0.218	-0.154	0.302	0.672***
	(0.175)	*(0.232)*	*(0.217)*	*(0.238)*	*(0.247)*	*(0.219)*	*(0.263)*	*(0.178)*	*(0.196)*	*(0.179)*	*(0.185)*	*(0.168)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	4,320	4,608	8,928	8,640	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Seven Mile Hill Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.519***	0.865***	0.521***	0.705***	1.073***	0.833***	0.722***	0.720***	0.716***	0.787***	0.907***	0.872***
	(0.122)	*(0.115)*	*(0.116)*	*(0.100)*	*(0.113)*	*(0.134)*	*(0.0954)*	*(0.0860)*	*(0.0951)*	*(0.120)*	*(0.118)*	*(0.108)*
Capacity Factor Foote Creek [t-1]	-0.309	-0.366*	-0.00258	-0.218	-0.317*	-0.415*	-0.110	-0.0883	-0.0719	-0.323	-0.375*	-0.387**
	(0.228)	*(0.206)*	*(0.195)*	*(0.173)*	*(0.185)*	*(0.247)*	*(0.161)*	*(0.144)*	*(0.159)*	*(0.212)*	*(0.209)*	*(0.191)*
Capacity Factor Foote Creek [t-2]	0.127	0.135	0.0807	0.104	0.0968	0.247	0.124	0.147	0.106	0.164	0.152	0.103
	(0.249)	*(0.218)*	*(0.203)*	*(0.180)*	*(0.188)*	*(0.271)*	*(0.169)*	*(0.150)*	*(0.164)*	*(0.225)*	*(0.221)*	*(0.198)*
Capacity Factor Foote Creek [t-3]	-0.0283	-0.0230	-0.0466	0.00180	0.000586	0.00521	0.161	0.0237	-0.0534	0.00176	-0.0393	-0.0567
	(0.251)	*(0.218)*	*(0.203)*	*(0.180)*	*(0.188)*	*(0.273)*	*(0.169)*	*(0.151)*	*(0.164)*	*(0.227)*	*(0.222)*	*(0.198)*
Capacity Factor Foote Creek [t-4]	0.126	0.120	0.109	0.0881	0.0325	0.140	0.0899	0.0209	0.105	0.0975	0.145	0.0793
	(0.249)	*(0.218)*	*(0.203)*	*(0.180)*	*(0.188)*	*(0.271)*	*(0.169)*	*(0.151)*	*(0.164)*	*(0.225)*	*(0.221)*	*(0.198)*
Capacity Factor Foote Creek [t-5]	-0.302	-0.382*	-0.0425	-0.0821	-0.0763	-0.120	-0.0786	-0.0998	-0.0207	-0.175	-0.295	-0.223
	(0.228)	*(0.206)*	*(0.195)*	*(0.172)*	*(0.184)*	*(0.248)*	*(0.163)*	*(0.145)*	*(0.160)*	*(0.212)*	*(0.209)*	*(0.189)*
Capacity Factor Foote Creek [t-6]	0.519***	0.770***	0.336***	0.453***	0.350***	0.217	0.269***	0.242***	0.337***	0.493***	0.805***	0.521***
	(0.121)	*(0.115)*	*(0.116)*	*(0.100)*	*(0.111)*	*(0.135)*	*(0.0961)*	*(0.0867)*	*(0.0955)*	*(0.120)*	*(0.118)*	*(0.107)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	4,320	4,464	4,464	4,320	4,464	4,320	4,608

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Mountain Wind Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.522***	0.614***	0.639***	0.372**	0.338***	0.303***	0.749***	0.495***	0.435***	0.527***	0.664***	0.806***
	(0.175)	*(0.217)*	*(0.129)*	*(0.160)*	*(0.128)*	*(0.110)*	*(0.138)*	*(0.149)*	*(0.154)*	*(0.123)*	*(0.126)*	*(0.124)*
Capacity Factor Foote Creek [t-1]	-0.333	-0.291	-0.183	-0.146	-0.0689	-0.158	-0.262	-0.184	-0.158	-0.204	-0.263	-0.373*
	(0.329)	*(0.389)*	*(0.217)*	*(0.276)*	*(0.211)*	*(0.202)*	*(0.233)*	*(0.250)*	*(0.257)*	*(0.211)*	*(0.224)*	*(0.222)*
Capacity Factor Foote Creek [t-2]	0.129	0.0805	0.0961	0.0198	0.0127	0.134	0.0493	0.102	0.0790	0.0825	0.135	0.104
	(0.359)	*(0.411)*	*(0.225)*	*(0.288)*	*(0.216)*	*(0.221)*	*(0.243)*	*(0.261)*	*(0.265)*	*(0.220)*	*(0.237)*	*(0.235)*
Capacity Factor Foote Creek [t-3]	-0.0548	-0.0821	-0.0349	-0.0195	0.0322	0.000107	0.137	0.00232	-0.0552	-0.00161	-0.0200	-0.102
	(0.362)	*(0.413)*	*(0.226)*	*(0.289)*	*(0.216)*	*(0.223)*	*(0.243)*	*(0.262)*	*(0.265)*	*(0.221)*	*(0.238)*	*(0.236)*
Capacity Factor Foote Creek [t-4]	0.146	0.0787	0.0767	0.0641	0.0273	0.0867	-0.0219	0.0359	0.118	0.0481	0.0241	0.0787
	(0.359)	*(0.412)*	*(0.225)*	*(0.288)*	*(0.216)*	*(0.221)*	*(0.243)*	*(0.261)*	*(0.265)*	*(0.220)*	*(0.237)*	*(0.235)*
Capacity Factor Foote Creek [t-5]	-0.339	-0.0256	-0.0428	-0.210	-0.0462	-0.0963	0.0567	-0.131	-0.174	-0.131	-0.0237	-0.287
	(0.329)	*(0.390)*	*(0.217)*	*(0.276)*	*(0.211)*	*(0.202)*	*(0.234)*	*(0.251)*	*(0.257)*	*(0.211)*	*(0.224)*	*(0.222)*
Capacity Factor Foote Creek [t-6]	0.545***	0.0835	0.305**	0.445***	0.400***	0.248**	0.0834	0.325**	0.676***	0.314**	0.112	0.580***
	(0.175)	*(0.217)*	*(0.129)*	*(0.160)*	*(0.128)*	*(0.110)*	*(0.138)*	*(0.150)*	*(0.154)*	*(0.123)*	*(0.126)*	*(0.124)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	4,320	4,464	4,464	4,608	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Marengo Predicted by Combine Hills

	Estimated Coefficients											
Explanatory Variables	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Capacity Factor Combine Hills [t]	0.486***	0.372***	0.360***	0.482***	0.487***	0.234***	0.307***	0.295***	0.353***	0.594***	0.493***	0.760***
	(0.182)	*(0.113)*	*(0.0969)*	*(0.122)*	*(0.0869)*	*(0.0862)*	*(0.0803)*	*(0.0722)*	*(0.0805)*	*(0.0868)*	*(0.0903)*	*(0.111)*
Capacity Factor Combine Hills [t-1]	-0.271	-0.109	-0.129	-0.235	-0.226	-0.131	-0.186	-0.146	-0.160	-0.328**	-0.228	-0.336*
	(0.336)	*(0.197)*	*(0.177)*	*(0.219)*	*(0.157)*	*(0.158)*	*(0.145)*	*(0.136)*	*(0.147)*	*(0.161)*	*(0.164)*	*(0.199)*
Capacity Factor Combine Hills [t-2]	0.182	0.151	0.135	0.0636	0.0711	0.0448	0.0484	0.0365	0.0837	0.134	0.113	0.170
	(0.364)	*(0.211)*	*(0.192)*	*(0.230)*	*(0.166)*	*(0.168)*	*(0.150)*	*(0.146)*	*(0.158)*	*(0.173)*	*(0.175)*	*(0.211)*
Capacity Factor Combine Hills [t-3]	-0.00779	-0.0543	-0.165	-0.0483	-0.0264	0.00555	0.0109	-0.00229	-0.128	-0.109	-0.0854	0.0328
	(0.365)	*(0.212)*	*(0.194)*	*(0.231)*	*(0.166)*	*(0.168)*	*(0.150)*	*(0.147)*	*(0.160)*	*(0.174)*	*(0.176)*	*(0.212)*
Capacity Factor Combine Hills [t-4]	0.0761	0.0545	0.243	0.113	0.138	0.0672	-0.0142	0.112	0.198	0.168	0.155	0.116
	(0.364)	*(0.209)*	*(0.192)*	*(0.230)*	*(0.167)*	*(0.166)*	*(0.150)*	*(0.147)*	*(0.158)*	*(0.173)*	*(0.175)*	*(0.211)*
Capacity Factor Combine Hills [t-5]	-0.0275	-0.145	-0.556***	-0.508**	-0.325**	-0.393**	-0.438***	-0.484***	-0.406***	-0.458***	-0.294*	-0.197
	(0.336)	*(0.196)*	*(0.177)*	*(0.219)*	*(0.158)*	*(0.156)*	*(0.145)*	*(0.136)*	*(0.147)*	*(0.161)*	*(0.163)*	*(0.199)*
Capacity Factor Combine Hills [t-6]	0.179	0.452***	1.056***	0.950***	0.752***	0.839***	0.944***	0.879***	0.841***	0.839***	0.719***	0.483***
	(0.181)	*(0.112)*	*(0.0968)*	*(0.122)*	*(0.0872)*	*(0.0853)*	*(0.0800)*	*(0.0720)*	*(0.0801)*	*(0.0867)*	*(0.0901)*	*(0.111)*
Number of Observations	4,464	4,032	4,464	4,320	4,464	5,040	8,928	8,928	8,640	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Goodnoe Predicted by Leaning Juniper

	Estimated Coefficients											
Explanatory Variables	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Capacity Factor Leaning Juniper [t]	0.811***	0.730***	0.841***	0.877***	0.901***	0.762***	0.755***	0.703***	0.805***	0.682***	0.776***	0.748***
	(0.103)	*(0.126)*	*(0.0744)*	*(0.0820)*	*(0.0869)*	*(0.0520)*	*(0.0601)*	*(0.0541)*	*(0.0755)*	*(0.0552)*	*(0.0675)*	*(0.118)*
Capacity Factor Leaning Juniper [t-1]	-0.412**	-0.445*	-0.321**	-0.379***	-0.420***	-0.320***	-0.283***	-0.279***	-0.412***	-0.233**	-0.319***	-0.366*
	(0.189)	*(0.242)*	*(0.130)*	*(0.147)*	*(0.159)*	*(0.0910)*	*(0.103)*	*(0.0953)*	*(0.138)*	*(0.0961)*	*(0.119)*	*(0.217)*
Capacity Factor Leaning Juniper [t-2]	0.222	0.166	0.0314	0.164	0.177	0.0852	0.116	0.167*	0.161	0.120	0.160	0.166
	(0.205)	*(0.267)*	*(0.135)*	*(0.157)*	*(0.171)*	*(0.0956)*	*(0.108)*	*(0.101)*	*(0.148)*	*(0.102)*	*(0.126)*	*(0.233)*
Capacity Factor Leaning Juniper [t-3]	-0.0369	-0.0679	0.0631	0.0348	-0.00515	0.0395	-0.0405	-0.0296	0.0255	0.0218	-0.0387	-0.0299
	(0.206)	*(0.270)*	*(0.135)*	*(0.157)*	*(0.172)*	*(0.0960)*	*(0.108)*	*(0.102)*	*(0.148)*	*(0.102)*	*(0.127)*	*(0.234)*
Capacity Factor Leaning Juniper [t-4]	0.127	0.123	0.0597	0.0691	0.0812	0.0867	0.0846	0.127	0.0876	0.0641	0.106	0.114
	(0.205)	*(0.267)*	*(0.135)*	*(0.157)*	*(0.172)*	*(0.0958)*	*(0.108)*	*(0.101)*	*(0.148)*	*(0.102)*	*(0.126)*	*(0.233)*
Capacity Factor Leaning Juniper [t-5]	-0.130	-0.291	0.00342	-0.127	-0.102	-0.121	-0.135	-0.142	-0.180	-0.0979	-0.122	-0.205
	(0.189)	*(0.242)*	*(0.130)*	*(0.147)*	*(0.161)*	*(0.0914)*	*(0.103)*	*(0.0952)*	*(0.138)*	*(0.0962)*	*(0.119)*	*(0.217)*
Capacity Factor Leaning Juniper [t-6]	0.324***	0.470***	0.267***	0.294***	0.305***	0.291***	0.339***	0.343***	0.360***	0.349***	0.389***	0.400***
	(0.103)	*(0.126)*	*(0.0744)*	*(0.0819)*	*(0.0873)*	*(0.0521)*	*(0.0601)*	*(0.0540)*	*(0.0757)*	*(0.0551)*	*(0.0675)*	*(0.118)*
Number of Observations	4,464	4,032	4,464	4,320	4,608	8,640	8,928	8,928	8,640	8,928	8,640	8,928

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Top of the World Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.368***	0.327***	0.275***	0.194***	0.0788**	0.101***	0.0683***	0.0724***	0.137***	0.202***	0.395***	0.416***
	(0.0643)	*(0.0623)*	*(0.0500)*	*(0.0391)*	*(0.0316)*	*(0.0243)*	*(0.0223)*	*(0.0260)*	*(0.0300)*	*(0.0449)*	*(0.0619)*	*(0.0577)*
Capacity Factor Foote Creek [t-1]	0.0545	0.0482	0.0451	0.00184	0.0524	0.00127	0.0123	-0.0122	0.0202	0.0312	0.103	0.0662
	(0.0843)	*(0.0828)*	*(0.0674)*	*(0.0521)*	*(0.0414)*	*(0.0327)*	*(0.0298)*	*(0.0355)*	*(0.0412)*	*(0.0593)*	*(0.0794)*	*(0.0768)*
Capacity Factor Foote Creek [t-2]	-0.0469	0.0164	-0.0208	0.0212	0.0251	0.0268	7.50e-05	0.0251	0.0246	0.00170	-0.0110	0.00624
	(0.0857)	*(0.0835)*	*(0.0677)*	*(0.0523)*	*(0.0415)*	*(0.0327)*	*(0.0297)*	*(0.0355)*	*(0.0412)*	*(0.0596)*	*(0.0805)*	*(0.0771)*
Capacity Factor Foote Creek [t-3]	-0.0369	-0.0183	-0.00578	0.0170	0.00300	0.0202	0.0107	0.0229	0.00661	0.000210	0.0185	-0.0236
	(0.0855)	*(0.0835)*	*(0.0677)*	*(0.0523)*	*(0.0415)*	*(0.0327)*	*(0.0297)*	*(0.0355)*	*(0.0413)*	*(0.0596)*	*(0.0806)*	*(0.0774)*
Capacity Factor Foote Creek [t-4]	-0.0152	0.00696	-0.00881	0.0368	0.0260	0.0321	0.0133	-0.00532	0.00566	0.0176	-0.0311	-0.00378
	(0.0856)	*(0.0836)*	*(0.0678)*	*(0.0522)*	*(0.0415)*	*(0.0328)*	*(0.0296)*	*(0.0356)*	*(0.0413)*	*(0.0596)*	*(0.0805)*	*(0.0774)*
Capacity Factor Foote Creek [t-5]	0.0884	0.0553	0.0489	0.0240	0.0380	0.0151	-0.0174	0.0350	0.00410	0.0615	0.0477	0.0482
	(0.0844)	*(0.0828)*	*(0.0674)*	*(0.0521)*	*(0.0414)*	*(0.0328)*	*(0.0296)*	*(0.0356)*	*(0.0412)*	*(0.0592)*	*(0.0796)*	*(0.0769)*
Capacity Factor Foote Creek [t-6]	0.365***	0.239***	0.243***	0.238***	0.144***	0.159***	0.0577***	0.125***	0.153***	0.249***	0.266***	0.365***
	(0.0644)	*(0.0624)*	*(0.0500)*	*(0.0391)*	*(0.0316)*	*(0.0243)*	*(0.0222)*	*(0.0261)*	*(0.0300)*	*(0.0448)*	*(0.0620)*	*(0.0578)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Three Buttes Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.347***	0.284***	0.299***	0.201***	0.0910***	0.122***	0.0774***	0.0606**	0.128***	0.184***	0.394***	0.389***
	(0.0602)	*(0.0612)*	*(0.0465)*	*(0.0406)*	*(0.0314)*	*(0.0250)*	*(0.0217)*	*(0.0273)*	*(0.0287)*	*(0.0447)*	*(0.0604)*	*(0.0559)*
Capacity Factor Foote Creek [t-1]	0.0552	0.0508	0.0395	0.00591	0.0290	0.0116	0.00723	0.0320	0.00576	0.0335	0.0977	0.0541
	(0.0789)	*(0.0813)*	*(0.0627)*	*(0.0540)*	*(0.0411)*	*(0.0337)*	*(0.0290)*	*(0.0372)*	*(0.0394)*	*(0.0588)*	*(0.0776)*	*(0.0747)*
Capacity Factor Foote Creek [t-2]	-0.0260	0.00141	-0.00890	0.0211	0.0119	0.0118	0.0286	0.0344	0.0199	0.0135	-0.0355	0.0155
	(0.0801)	*(0.0821)*	*(0.0630)*	*(0.0542)*	*(0.0411)*	*(0.0338)*	*(0.0290)*	*(0.0372)*	*(0.0394)*	*(0.0592)*	*(0.0787)*	*(0.0754)*
Capacity Factor Foote Creek [t-3]	-0.0199	0.0114	0.0108	0.0197	0.0300	0.0244	-0.0105	0.00457	0.0208	0.0216	-0.000275	-0.00758
	(0.0798)	*(0.0820)*	*(0.0631)*	*(0.0542)*	*(0.0411)*	*(0.0338)*	*(0.0290)*	*(0.0372)*	*(0.0394)*	*(0.0592)*	*(0.0787)*	*(0.0755)*
Capacity Factor Foote Creek [t-4]	-0.0358	-0.0225	-0.00289	-0.000622	0.0185	0.0152	0.000939	0.0212	0.00602	0.00727	-0.0350	-0.0196
	(0.0800)	*(0.0821)*	*(0.0630)*	*(0.0542)*	*(0.0412)*	*(0.0338)*	*(0.0289)*	*(0.0372)*	*(0.0394)*	*(0.0593)*	*(0.0788)*	*(0.0755)*
Capacity Factor Foote Creek [t-5]	0.0651	0.0465	0.00235	0.0502	0.0142	0.0313	0.0117	-0.00139	0.00699	0.0327	0.0617	0.0364
	(0.0789)	*(0.0814)*	*(0.0626)*	*(0.0540)*	*(0.0411)*	*(0.0338)*	*(0.0289)*	*(0.0373)*	*(0.0394)*	*(0.0590)*	*(0.0778)*	*(0.0751)*
Capacity Factor Foote Creek [t-6]	0.329***	0.270***	0.206***	0.221***	0.156***	0.162***	0.0388*	0.119***	0.154***	0.244***	0.242***	0.331***
	(0.0603)	*(0.0613)*	*(0.0465)*	*(0.0406)*	*(0.0314)*	*(0.0250)*	*(0.0216)*	*(0.0274)*	*(0.0286)*	*(0.0446)*	*(0.0605)*	*(0.0563)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Dunlap Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.450***	0.292***	0.352***	0.234***	0.114***	0.161***	0.104***	0.134***	0.176***	0.278***	0.408***	0.447***
	(0.0478)	*(0.0441)*	*(0.0378)*	*(0.0285)*	*(0.0237)*	*(0.0186)*	*(0.0140)*	*(0.0168)*	*(0.0214)*	*(0.0366)*	*(0.0458)*	*(0.0488)*
Capacity Factor Foote Creek [t-1]	0.0665	0.0726	0.0582	0.0495	0.0409	0.0313	0.0518***	0.0298	0.0542*	0.0676	0.112*	0.0523
	(0.0624)	*(0.0587)*	*(0.0510)*	*(0.0379)*	*(0.0310)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0483)*	*(0.0588)*	*(0.0652)*
Capacity Factor Foote Creek [t-2]	-0.00458	-0.0240	-0.0135	0.0126	0.0678**	0.0369	0.0250	0.0311	0.0447	0.00626	0.00486	0.00843
	(0.0635)	*(0.0592)*	*(0.0513)*	*(0.0381)*	*(0.0311)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0486)*	*(0.0596)*	*(0.0655)*
Capacity Factor Foote Creek [t-3]	-0.0151	0.0472	-0.00555	0.00570	0.0440	0.0429*	0.0163	0.0196	0.0232	-0.00101	-0.0307	-0.0148
	(0.0636)	*(0.0591)*	*(0.0513)*	*(0.0381)*	*(0.0311)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0486)*	*(0.0595)*	*(0.0656)*
Capacity Factor Foote Creek [t-4]	-0.0355	-0.0389	0.00531	0.0189	0.0356	0.0318	0.0173	0.0247	-0.00119	-0.000509	0.00812	0.0296
	(0.0635)	*(0.0592)*	*(0.0513)*	*(0.0380)*	*(0.0311)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0486)*	*(0.0595)*	*(0.0657)*
Capacity Factor Foote Creek [t-5]	0.0849	0.0637	0.00670	0.0516	0.0435	0.0361	-0.00205	0.0201	-0.00276	0.0434	0.0525	0.0145
	(0.0624)	*(0.0587)*	*(0.0509)*	*(0.0379)*	*(0.0310)*	*(0.0251)*	*(0.0186)*	*(0.0228)*	*(0.0294)*	*(0.0484)*	*(0.0588)*	*(0.0652)*
Capacity Factor Foote Creek [t-6]	0.367***	0.385***	0.282***	0.239***	0.150***	0.119***	0.0783***	0.120***	0.147***	0.289***	0.277***	0.388***
	(0.0476)	*(0.0440)*	*(0.0377)*	*(0.0284)*	*(0.0236)*	*(0.0186)*	*(0.0140)*	*(0.0168)*	*(0.0214)*	*(0.0366)*	*(0.0457)*	*(0.0489)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Rolling Hills Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.372***	0.334***	0.310***	0.213***	0.0919***	0.119***	0.0854***	0.0756***	0.144***	0.224***	0.392***	0.414***
	(0.0635)	*(0.0631)*	*(0.0490)*	*(0.0405)*	*(0.0318)*	*(0.0252)*	*(0.0223)*	*(0.0267)*	*(0.0303)*	*(0.0457)*	*(0.0619)*	*(0.0590)*
Capacity Factor Foote Creek [t-1]	0.0571	0.0678	0.0577	0.0329	0.0321	0.0383	-0.00870	0.00443	0.0205	0.0232	0.0809	0.0331
	(0.0832)	*(0.0838)*	*(0.0660)*	*(0.0539)*	*(0.0416)*	*(0.0340)*	*(0.0298)*	*(0.0362)*	*(0.0417)*	*(0.0604)*	*(0.0795)*	*(0.0788)*
Capacity Factor Foote Creek [t-2]	-0.0482	-0.00447	-0.0226	0.0145	0.0318	0.0134	0.0186	0.0355	-0.00162	0.0120	0.0158	0.0364
	(0.0846)	*(0.0846)*	*(0.0664)*	*(0.0541)*	*(0.0417)*	*(0.0341)*	*(0.0297)*	*(0.0362)*	*(0.0418)*	*(0.0605)*	*(0.0804)*	*(0.0791)*
Capacity Factor Foote Creek [t-3]	-0.0268	-0.0390	-0.0218	0.0237	0.0244	0.0130	0.0108	0.0189	0.0227	0.00717	-0.0234	-0.00569
	(0.0845)	*(0.0846)*	*(0.0664)*	*(0.0541)*	*(0.0417)*	*(0.0340)*	*(0.0297)*	*(0.0362)*	*(0.0419)*	*(0.0607)*	*(0.0803)*	*(0.0792)*
Capacity Factor Foote Creek [t-4]	-0.0226	-0.00151	-0.0163	0.0253	0.0162	0.0160	0.0123	0.0139	0.00500	0.01000	-0.00365	0.00189
	(0.0844)	*(0.0847)*	*(0.0664)*	*(0.0541)*	*(0.0417)*	*(0.0340)*	*(0.0297)*	*(0.0362)*	*(0.0418)*	*(0.0607)*	*(0.0804)*	*(0.0793)*
Capacity Factor Foote Creek [t-5]	0.0468	0.0350	0.0432	0.0216	0.0334	0.0344	-0.0196	0.0162	0.0129	0.0313	0.0881	0.0672
	(0.0830)	*(0.0838)*	*(0.0659)*	*(0.0539)*	*(0.0416)*	*(0.0340)*	*(0.0297)*	*(0.0362)*	*(0.0417)*	*(0.0604)*	*(0.0796)*	*(0.0788)*
Capacity Factor Foote Creek [t-6]	0.383***	0.279***	0.235***	0.231***	0.150***	0.163***	0.0720***	0.113***	0.162***	0.269***	0.225***	0.312***
	(0.0633)	*(0.0632)*	*(0.0489)*	*(0.0405)*	*(0.0318)*	*(0.0252)*	*(0.0222)*	*(0.0266)*	*(0.0303)*	*(0.0457)*	*(0.0620)*	*(0.0593)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for Rock River Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Capacity Factor Foote Creek [t]	0.697***	0.614***	0.723***	0.733***	0.702***	0.708***	0.727***	0.685***	0.746***	0.680***	0.700***	0.681***
	(0.0257)	*(0.0206)*	*(0.0198)*	*(0.0182)*	*(0.0126)*	*(0.0129)*	*(0.0116)*	*(0.0128)*	*(0.0145)*	*(0.0187)*	*(0.0245)*	*(0.0261)*
Capacity Factor Foote Creek [t-1]	0.169***	0.224***	0.190***	0.173***	0.141***	0.105***	0.104***	0.146***	0.127***	0.185***	0.212***	0.167***
	(0.0337)	*(0.0275)*	*(0.0269)*	*(0.0242)*	*(0.0165)*	*(0.0174)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0247)*	*(0.0316)*	*(0.0350)*
Capacity Factor Foote Creek [t-2]	0.0506	0.0688**	0.0670**	0.0322	0.0253	0.0207	0.0247	0.0315*	-0.0103	0.0492**	0.0506	0.0486
	(0.0343)	*(0.0278)*	*(0.0271)*	*(0.0244)*	*(0.0165)*	*(0.0174)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0248)*	*(0.0320)*	*(0.0354)*
Capacity Factor Foote Creek [t-3]	0.0220	0.0364	0.0287	-0.0120	0.0291*	0.0512***	0.0268*	0.0158	0.0310	0.00557	0.0150	-0.00890
	(0.0344)	*(0.0278)*	*(0.0272)*	*(0.0244)*	*(0.0166)*	*(0.0175)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0249)*	*(0.0321)*	*(0.0355)*
Capacity Factor Foote Creek [t-4]	0.000164	-0.0105	0.0138	0.00796	0.0376**	-0.0108	0.00877	0.0250	0.0424**	0.0261	-0.00958	0.0228
	(0.0346)	*(0.0279)*	*(0.0272)*	*(0.0244)*	*(0.0166)*	*(0.0175)*	*(0.0155)*	*(0.0174)*	*(0.0199)*	*(0.0249)*	*(0.0321)*	*(0.0356)*
Capacity Factor Foote Creek [t-5]	0.000294	0.0494*	0.0205	0.00953	0.0165	0.0349**	0.0211	0.0118	0.00483	0.0240	0.00374	0.0274
	(0.0341)	*(0.0278)*	*(0.0273)*	*(0.0243)*	*(0.0166)*	*(0.0175)*	*(0.0155)*	*(0.0175)*	*(0.0199)*	*(0.0248)*	*(0.0318)*	*(0.0356)*
Capacity Factor Foote Creek [t-6]	0.116***	0.0503**	-0.0140	0.0660***	0.0248*	0.0505***	0.0125	0.0255**	0.0436***	0.0427**	0.0719***	0.126***
	(0.0259)	*(0.0209)*	*(0.0203)*	*(0.0183)*	*(0.0126)*	*(0.0130)*	*(0.0117)*	*(0.0129)*	*(0.0145)*	*(0.0189)*	*(0.0247)*	*(0.0268)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for McFadden Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Capacity Factor Foote Creek [t]	0.461***	0.329***	0.284***	0.297***	0.196***	0.168***	0.155***	0.177***	0.220***	0.240***	0.297***	0.404***
	(0.0522)	*(0.0429)*	*(0.0363)*	*(0.0304)*	*(0.0216)*	*(0.0205)*	*(0.0196)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0484)*	*(0.0446)*
Capacity Factor Foote Creek [t-1]	0.0625	0.0793	0.0563	0.139***	0.141***	0.144***	0.145***	0.106***	0.160***	0.124***	0.122**	0.0597
	(0.0684)	*(0.0571)*	*(0.0490)*	*(0.0405)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0424)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-2]	-0.0579	0.0406	0.0375	0.0891**	0.194***	0.182***	0.202***	0.176***	0.118***	0.110***	0.0247	0.0458
	(0.0696)	*(0.0576)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0426)*	*(0.0628)*	*(0.0598)*
Capacity Factor Foote Creek [t-3]	-0.00530	0.0210	0.0248	0.0507	0.0834***	0.130***	0.0969***	0.1000***	0.0786**	0.0880**	0.0279	0.00789
	(0.0695)	*(0.0575)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0600)*
Capacity Factor Foote Creek [t-4]	0.0353	0.00324	0.00366	0.0158	0.0435	0.0303	0.0332	0.0287	0.0465	0.0255	0.0414	-0.0257
	(0.0694)	*(0.0576)*	*(0.0492)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0602)*
Capacity Factor Foote Creek [t-5]	0.0822	0.0794	0.0859*	0.0525	0.0447	0.0170	0.00342	0.0192	0.00913	0.0133	0.0704	0.0689
	(0.0683)	*(0.0571)*	*(0.0489)*	*(0.0405)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-6]	0.322***	0.328***	0.377***	0.201***	0.107***	0.0697***	0.0844***	0.0662***	0.0966***	0.228***	0.254***	0.423***
	(0.0520)	*(0.0429)*	*(0.0362)*	*(0.0304)*	*(0.0216)*	*(0.0206)*	*(0.0195)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0483)*	*(0.0448)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Regression Results by Month for High Plains Predicted by Foote Creek

	Estimated Coefficients											
Explanatory Variables	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Capacity Factor Foote Creek [t]	0.461***	0.329***	0.284***	0.297***	0.196***	0.168***	0.155***	0.177***	0.220***	0.240***	0.297***	0.404***
	(0.0522)	*(0.0429)*	*(0.0363)*	*(0.0304)*	*(0.0216)*	*(0.0205)*	*(0.0196)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0484)*	*(0.0446)*
Capacity Factor Foote Creek [t-1]	0.0625	0.0793	0.0563	0.139***	0.141***	0.144***	0.145***	0.106***	0.160***	0.124***	0.122**	0.0597
	(0.0684)	*(0.0571)*	*(0.0490)*	*(0.0405)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0424)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-2]	-0.0579	0.0406	0.0375	0.0891**	0.194***	0.182***	0.202***	0.176***	0.118***	0.110***	0.0247	0.0458
	(0.0696)	*(0.0576)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0276)*	*(0.0260)*	*(0.0301)*	*(0.0317)*	*(0.0426)*	*(0.0628)*	*(0.0598)*
Capacity Factor Foote Creek [t-3]	-0.00530	0.0210	0.0248	0.0507	0.0834***	0.130***	0.0969***	0.1000***	0.0786**	0.0880**	0.0279	0.00789
	(0.0695)	*(0.0575)*	*(0.0493)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0600)*
Capacity Factor Foote Creek [t-4]	0.0353	0.00324	0.00366	0.0158	0.0435	0.0303	0.0332	0.0287	0.0465	0.0255	0.0414	-0.0257
	(0.0694)	*(0.0576)*	*(0.0492)*	*(0.0407)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0629)*	*(0.0602)*
Capacity Factor Foote Creek [t-5]	0.0822	0.0794	0.0859*	0.0525	0.0447	0.0170	0.00342	0.0192	0.00913	0.0133	0.0704	0.0689
	(0.0683)	*(0.0571)*	*(0.0489)*	*(0.0405)*	*(0.0283)*	*(0.0277)*	*(0.0260)*	*(0.0300)*	*(0.0317)*	*(0.0426)*	*(0.0622)*	*(0.0596)*
Capacity Factor Foote Creek [t-6]	0.322***	0.328***	0.377***	0.201***	0.107***	0.0697***	0.0844***	0.0662***	0.0966***	0.228***	0.254***	0.423***
	(0.0520)	*(0.0429)*	*(0.0362)*	*(0.0304)*	*(0.0216)*	*(0.0206)*	*(0.0195)*	*(0.0221)*	*(0.0231)*	*(0.0322)*	*(0.0483)*	*(0.0448)*
Number of Observations	13,386	12,240	13,392	12,960	13,392	12,960	13,392	13,392	12,960	13,392	12,960	13,392

Note: Standard errors in parentheses.
*** p<0.01, ** p<0.05, * p<0.1

Appendix C

Operating Reserve Demand Seasonal Detail

This Appendix presents the monthly component operating reserve service demand calculated for the PacifiCorp East and West Balancing Authority Areas in the Study. The 1,372 MW and 1,833 MW penetration scenarios include some simulated wind data; the load-only and 425 MW penetration scenarios do not.

Table C1.West Balancing Authority Area, Load Only

	Load Following		Regulation	
	Up	Down	Up	Down
January	127	129	125	82
February	93	103	111	73
March	114	115	109	77
April	84	87	103	65
May	93	101	95	72
June	82	83	78	63
July	93	96	69	64
August	79	84	65	60
September	96	104	88	64
October	83	83	98	62
November	149	166	127	95
December	125	116	101	86

Table C2.West Balancing Authority Area, 425 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	132	134	131	91
February	104	110	117	82
March	128	124	118	92
April	96	96	110	78
May	108	109	102	84
June	103	96	88	80
July	110	105	78	79
August	98	94	76	77
September	105	107	94	73
October	97	88	104	74
November	157	169	133	103
December	132	121	106	94

Table C3. West Balancing Authority area, 1,372 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	153	150	171	139
February	122	122	152	129
March	160	152	152	140
April	133	122	150	121
May	135	131	136	123
June	131	123	127	118
July	128	122	110	104
August	118	113	103	104
September	125	121	118	101
October	124	105	126	104
November	181	180	152	131
December	159	138	142	131

Table C4. West Balancing Authority area, 1,833 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	153	150	171	139
February	124	124	152	129
March	162	154	152	140
April	136	123	150	121
May	137	133	136	123
June	133	125	127	118
July	129	123	110	104
August	120	115	103	104
September	126	122	118	101
October	125	106	126	104
November	182	180	152	131
December	161	139	142	131

Table C5. East Balancing Authority area, Load Only

	Load Following		Regulation	
	Up	Down	Up	Down
January	127	131	150	110
February	117	122	131	98
March	135	138	122	102
April	105	103	145	95
May	146	145	133	114
June	143	152	134	114
July	157	155	130	112
August	162	162	122	111
September	144	162	127	105
October	139	146	116	97
November	154	164	161	110
December	145	149	182	112

Table C6. East Balancing Authority Area, 425 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	132	135	152	113
February	120	125	134	101
March	139	142	124	105
April	112	107	148	99
May	151	148	137	118
June	148	155	137	118
July	161	157	132	115
August	165	164	124	114
September	149	165	130	109
October	143	150	119	101
November	158	168	163	113
December	150	154	185	116

Table C7. East Balancing Authority Area, 1,372 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	187	193	201	175
February	201	195	210	189
March	212	209	207	200
April	193	174	212	182
May	204	184	183	179
June	205	192	189	185
July	205	177	170	172
August	204	187	164	166
September	219	203	185	177
October	218	211	202	192
November	230	227	232	197
December	212	228	253	207

Table C8. East Balancing Authority area, 1,833 MW

	Load Following		Regulation	
	Up	Down	Up	Down
January	240	262	250	241
February	256	262	264	247
March	247	247	235	236
April	236	213	243	223
May	228	205	203	202
June	232	210	204	202
July	220	185	177	183
August	216	197	176	179
September	245	222	201	199
October	257	251	235	230
November	276	290	279	259
December	291	299	300	266

APPENDIX J – STOCHASTIC LOSS OF LOAD STUDY

Introduction

PacifiCorp evaluates the desired level of capacity planning reserves for each integrated resource plan. For the 2011 IRP, the Company conducted a stochastic loss of load study to help identify the target capacity planning reserve margin (PRM) to use for resource portfolio development. This study utilized the Company's stochastic production cost simulation system, Planning and Risk (PaR), to determine the relationship between PRM and resource adequacy as measured by Loss of Load Probability (LOLP) index. Loss of load probability represents the probability that generation in a given hour is insufficient to serve load. Accumulating the number of hours for which the system experiences unserved load over a given period, typically one year, yields the LOLP index. Once the relationship between LOLP and PRM is established for PacifiCorp's system, a target LOLP level is selected to determine the PRM for subsequent resource portfolio development. This report describes the loss of load study and modeling assumptions, the selection of a target loss of load criterion, and the adoption of a PRM for portfolio development. The last comprehensive stochastic study conducted was for PacifiCorp's 2004 IRP.[48] Major differences between this study and the last one include (1) significantly more wind resources and incorporation of incremental wind operating reserves in the resource portfolio simulations, (2) expansion of the transmission topology from two bubbles to 26, and (3) incorporation of energy efficiency programs as a resource with a reserve credit rather than a reduction to the load forecast.

Note that while this study reports the incremental resource cost for achieving a given loss of load frequency and associated reserve margin level using a standard reliability resource type, it does not assess the trade-off between reliability and cost or the optimal resource mix to achieve a given reliability level. PacifiCorp compares different resource portfolios based on the amount and cost of unserved load (megawatt-hours of "Energy Not Served" or ENS) resulting from stochastic simulations of many portfolios built to meet a given PRM level. This stochastic analysis reveals the reliability impacts and costs associated with different resource mixes.

Loss of Load Probability Metrics

The metric used to derive the LOLP index is Loss of Load Hours (LOLH). The PaR model records a LOLH event when load is not met for an hour. This condition results from unit outages that reduce available generation capacity in a load area below the load derived from the Monte Carlo draws conducted by the PaR model. The LOLH event also has an associated Energy Not Served value, which is the magnitude of the lost load for the hour.

[48] See Appendix N of the 2004 IRP Technical Appendix Volume.

The PaR model's reported LOLP index is the average number of LOLH events for PacifiCorp's 100-iteration Monte Carlo production cost simulation. This measure is thus a likelihood of experiencing a shortfall in any given hour for the stochastic Monte Carlo simulation.[49]

Simulation Period

PacifiCorp selected 2014 as the simulation test year for the LOLP study. This year aligns with the start of the 2014-2016 resource acquisition period targeted by the Company's All Source RFP issued to the market on December 2, 16 2009. This year also aligns with major planned Energy Gateway transmission additions: the Mona-Oquirrh segment of Energy Gateway Central by June 2013, and the Sigurd-Red Butte segment by June 2014.

Modeling Approach Overview

The LOLP modeling approach entailed adding incremental reliability resource capacity to a starting point resource portfolio to reach increasingly higher target PRM levels. Loads and resources reflect those of the September 21, 2010 preliminary capacity load & resource balance, as presented at the October 5, 2010 IRP public input meeting.[50] This balance uses the annual system coincident peak load forecast prepared in September 2010 for use in the Company's 2011 business plan. The starting PRM level was 8.3 percent, which covers system operating reserve requirements (contingency and regulating reserves). Reliability resource capacity was then added to reach planning reserve margin levels of approximately 10 percent, 12 percent, 15 percent, and 18 percent. PacifiCorp conducted stochastic Monte Carlo simulations for each of the five resource portfolios built to achieve the target PRMs. The stochastic simulations account for Western Electricity Coordinating Council (WECC) operating reserve obligations plus incremental operating reserves for existing and forecasted wind additions as of year-end 2013. PacifiCorp then extracted LOLH and associated LOLP statistics from the portfolio simulations to characterize the reliability impacts of the incremental reliability resource capacity.

Planning Reserve Margin Build-Up

PacifiCorp used an intercooled aeroderivative simple-cycle combustion turbine (IC aero SCCT) as the reliability resource for the loss of load study. Starting from a portfolio with approximately a zero PRM, IC aero SCCT capacity blocks were added to PacifiCorp's East and West Balancing Authority Areas—PacifiCorp East (PACE) and PacifiCorp West (PACW)—until reaching the desired PRM. The capacity build-up includes 77 MW of non-owned reserves held for other parties located in PacifiCorp's Balancing Authority Areas, and accounts for the treatment of dispatchable load control (Class 1 DSM), interruptible load contracts, and purchases in the

[49] Calculating a probability using LOLH is a variant of the Loss of Load Expectation (LOLE) statistic.
[50] The preliminary 2011 IRP capacity load and resource balance is reported on page 45 of the meeting presentation, which can be downloaded at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PacifiCorp_2011IRP_PIM4_10-05-10.pdf

calculation of the reserve margin (See Chapter 5 for more details). Additionally, since the capacity balance uses a load forecast before energy efficiency (Class 2 DSM) load reductions are applied (the "pre-DSM" load forecast), PacifiCorp included a reserve credit for the incremental 307 MW of Class 2 DSM capacity added by 2014. Modeled SCCT units were sized as follows by Balancing Authority Area:

- PacifiCorp East Units - 93 MW (1 unit), 186 MW (2 Units), 279 MW (3 Units)
- PacifiCorp West Units - 102 MW (1 unit), 205 MW (2 Units), 307 MW (3 Units)

Regarding resource placement, PacifiCorp added SCCT capacity to transmission areas as dictated by PRM needs, with most resources placed in the West Main ("West Units") and Utah North ("East Units") transmission areas. Table J.1 shows the megawatt capacity added to reach the target PRM levels. Since capacity is added in blocks, the resulting PRM levels vary from the original target levels.

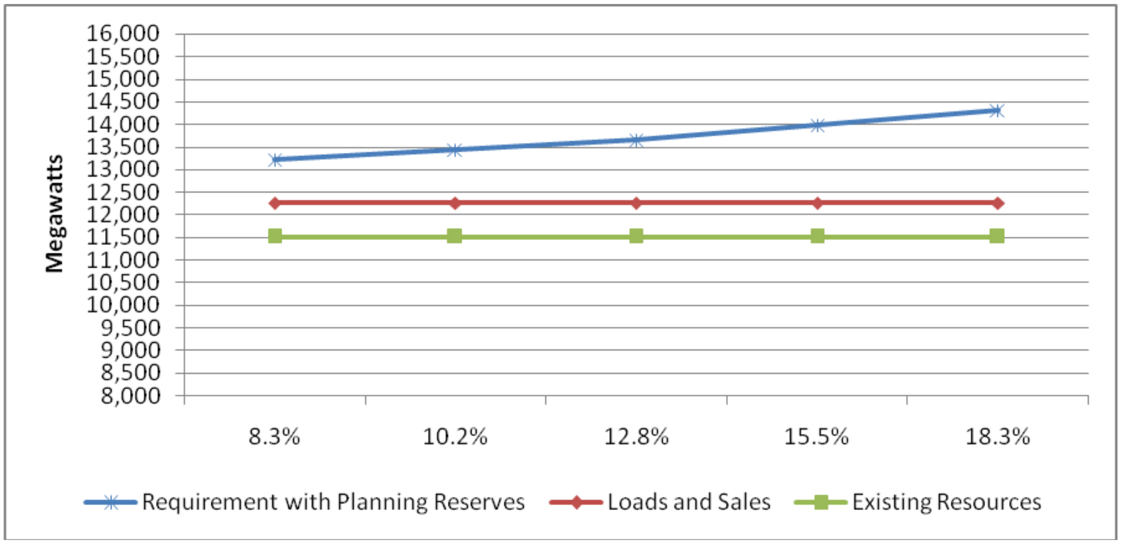
Table J.1 – Resource Capacity Additions Needed to Reach PRM Target Levels

	Planning Reserve Margin Level				
Resource	**8.3%**	**10.2%**	**12.8%**	**15.5%**	**18.3%**
East 3 Unit	837	1,116	1,116	1,395	1,674
East 2 Unit	186	0	186	0	0
East 1 Unit	0	0	0	93	0
Goshen	186	186	186	186	186
West 3 Unit	0	0	307	307	307
West 2 Unit	0	205	0	0	0
West 1 Unit	102	0	0	102	205
Walla Walla	102	102	102	102	102
Total IC Aero SCCT Capacity	**1,413**	**1,609**	**1,897**	**2,185**	**2,474**
DSM with Reserve Credit	**332**	**338**	**344**	**353**	**362**
Total Capacity Added*	**1,745**	**1,947**	**2,241**	**2,539**	**2,836**

* Excludes non-owned reserves held for other parties within PacifiCorp's service territory.

Figure J.1 shows the relative magnitude of existing resources, the load obligation plus sales, and resources with incremental reserves required to reach the target PRM.

Figure J.1 – Existing Resources, Loads & Sales, and Resources with Reserve Requirements



Monte Carlo Production Cost Simulation

For the loss of load study, the PaR model is configured to conduct 100 Monte Carlo simulation runs. During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable. The stochastic variables include regional loads, unit outages, hydro availability, commodity natural gas prices, and wholesale electricity prices. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. Figures 2 through 9 show a sample of first-of-month daily loads by transmission area resulting from the Monte Carlo draws. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Twelve representative weeks for each month, including the July system peak week, were modeled on an hourly basis. This representative-week approach reduces the model run-time requirements while ensuring that unit dispatch during the critical capacity planning periods is captured in the system simulations. Since only one year was simulated, the stochastic model's long-term stochastic parameters were turned off.

Figure J.2 – Utah North Load Area

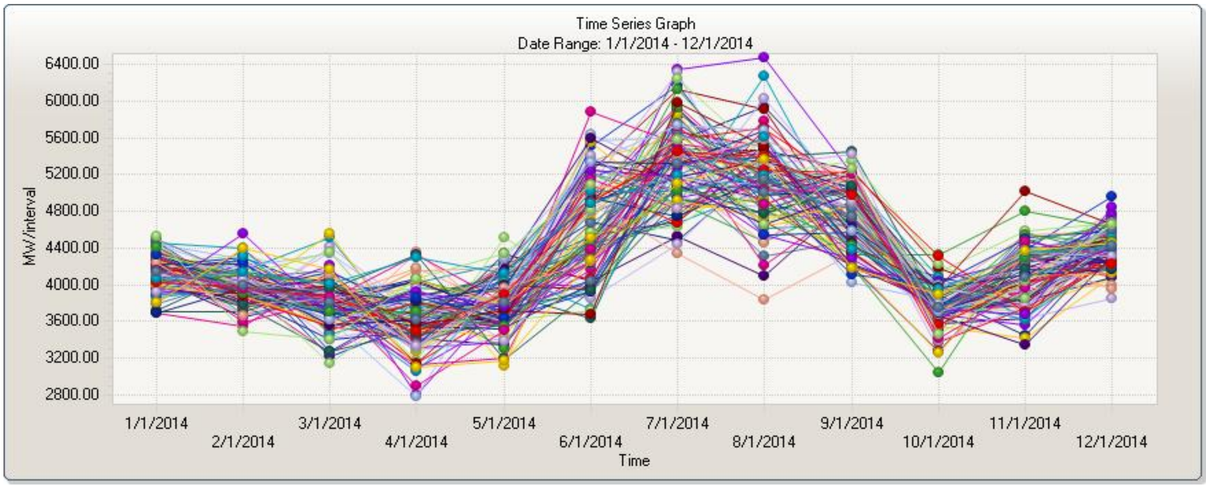


Figure J.3 – Utah South Load Area

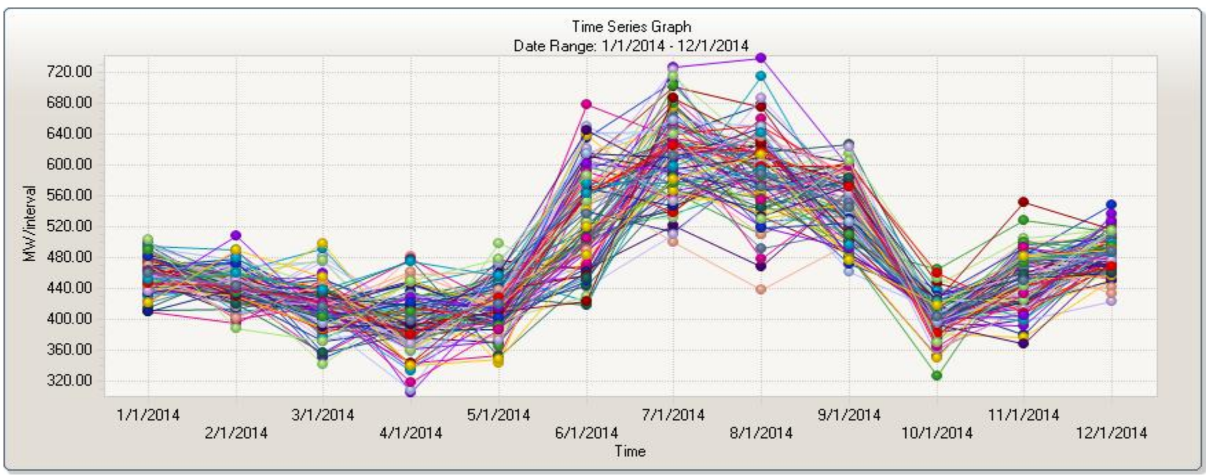


Figure J.4 – Walla Walla, Washington Load Area

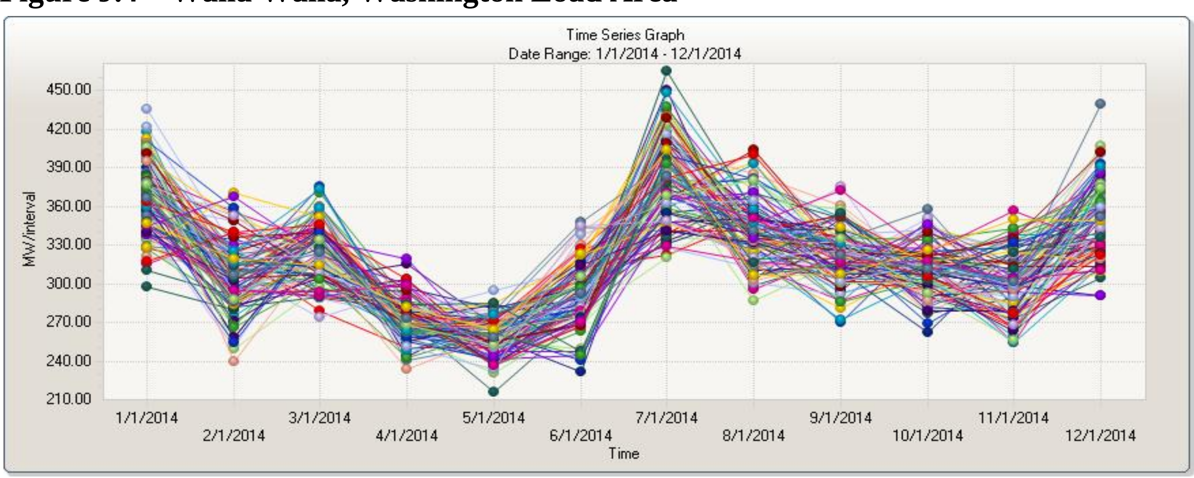


Figure J.5 – West Main (Oregon, Northern California) Load Area

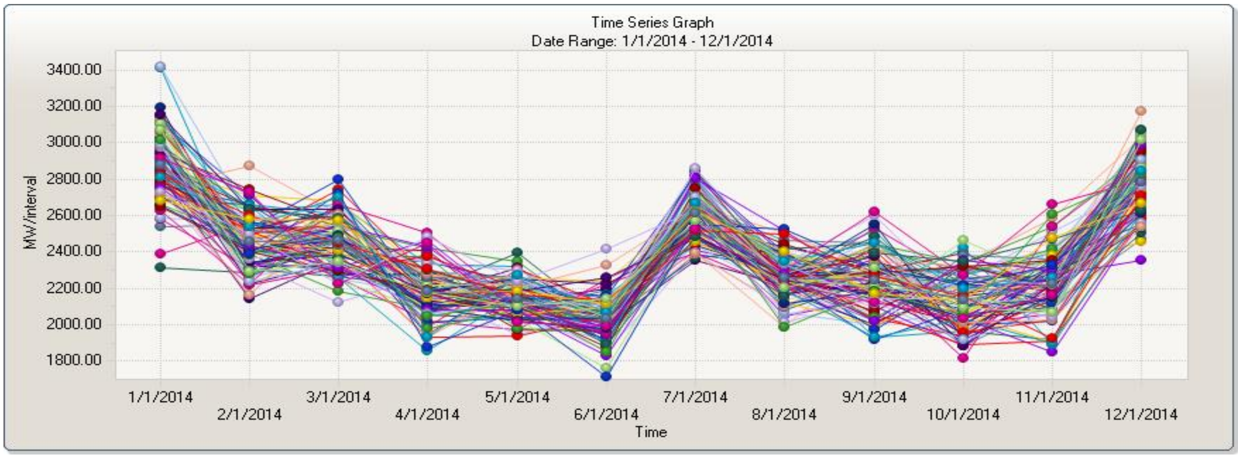


Figure J.6 – Yakima Load Area

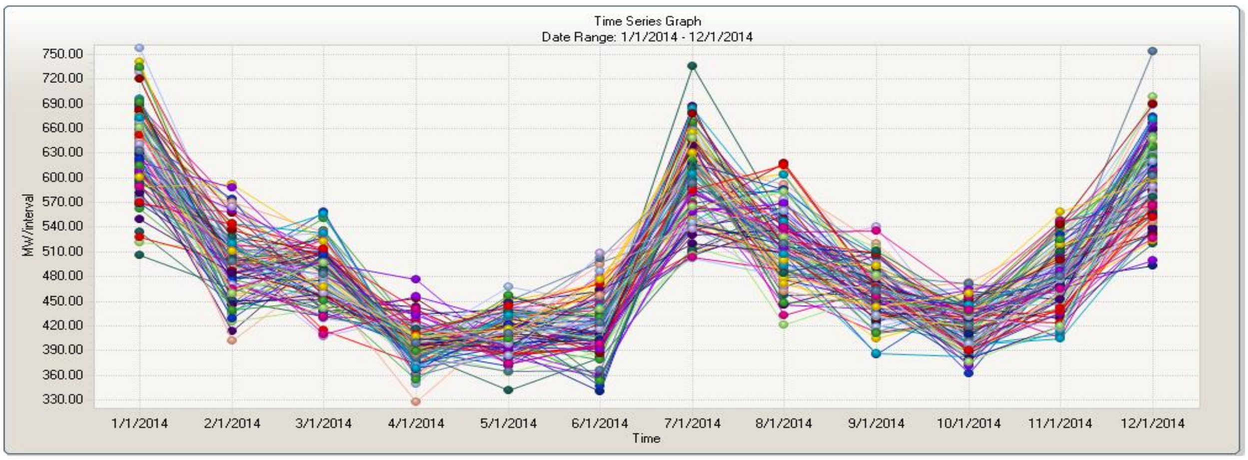


Figure J.7 – Goshen Idaho Load Area

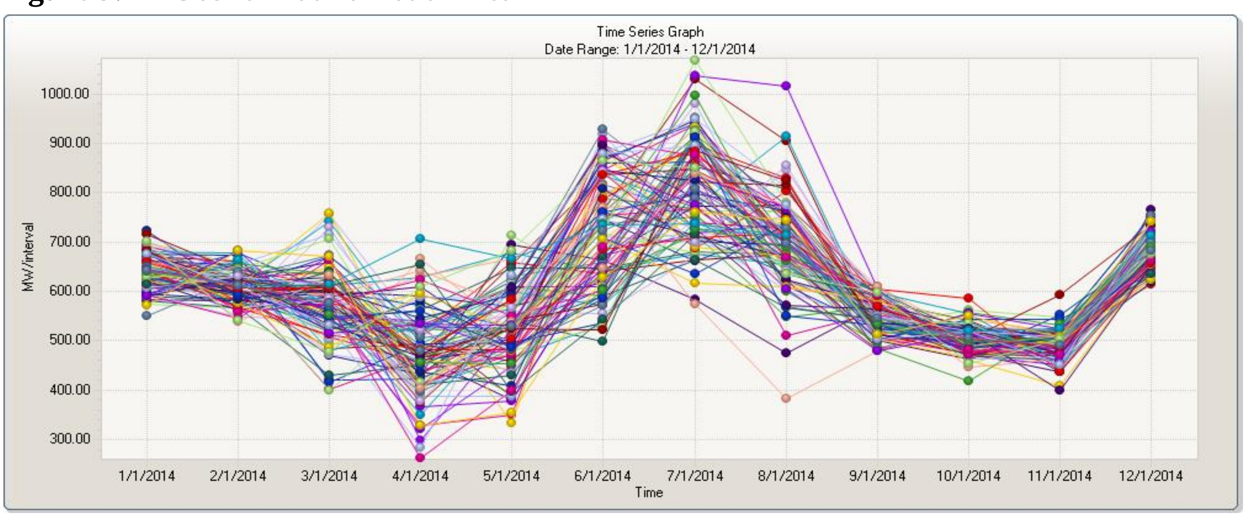


Figure J.8 – Northeast Wyoming Load Area

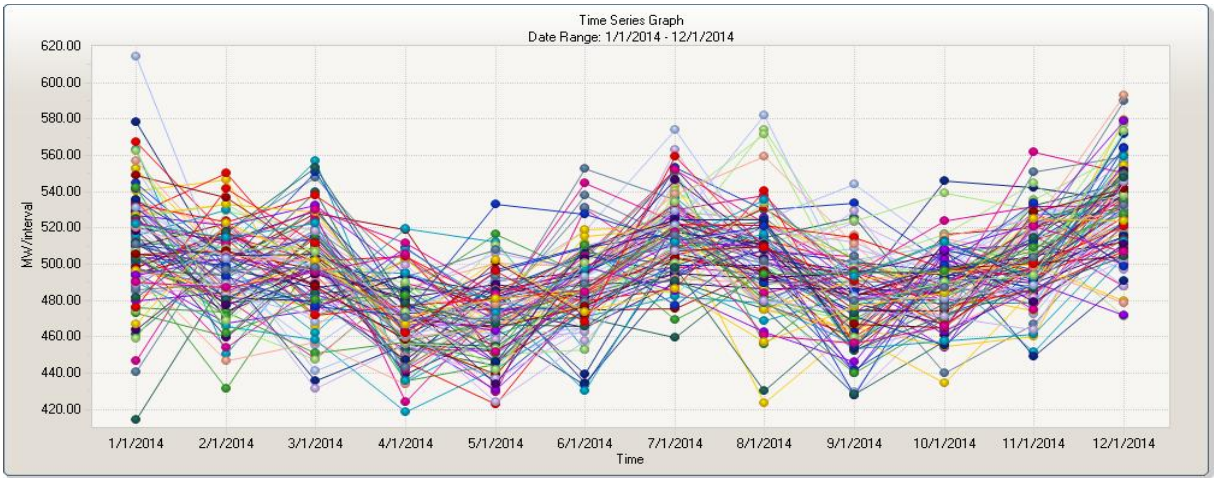
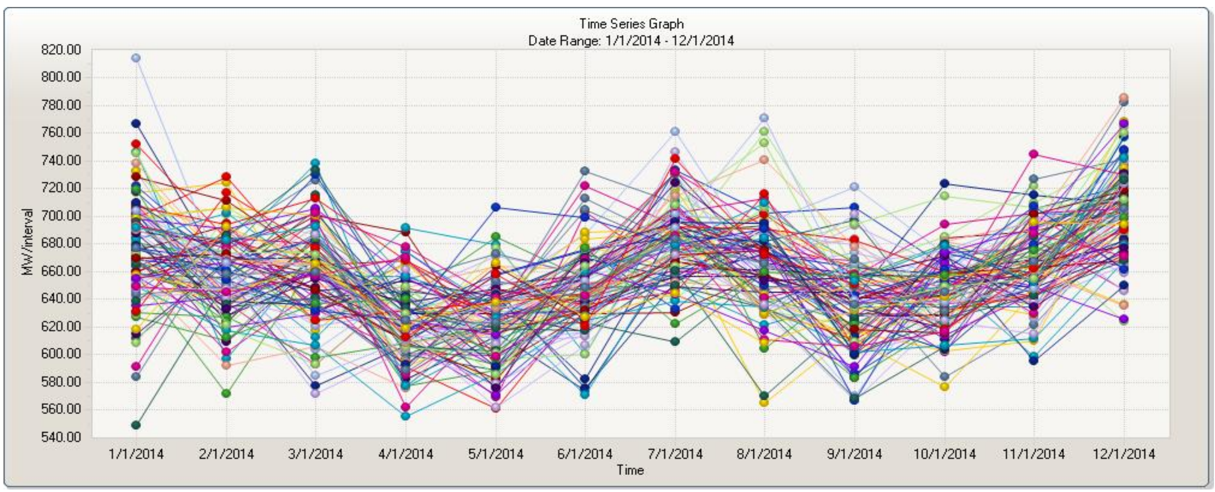


Figure J.9 – Southwest Wyoming Load Area



Modeling Operating Reserves

As part of the WECC, PacifiCorp is currently required to maintain at least 5 percent and 7 percent operating reserve margins on hydro and thermal load-serving resources, respectively. The Northwest Power Pool (NWPP) also requires a 5 percent operating reserve margin on wind. In the PaR model, operating reserves are modeled as a function of load. The maximum reserve amount that each generating unit can carry is specified in the model. The PaR model also includes 1.6 percent of loads to cover the WECC regulating reserves requirements. The operating reserve percentages, exclusive of wind, equate to 8.6 percent for the East Balancing Area and 8.1 percent for the West Balancing Area. These operating reserves are split into, roughly, 60-percent spinning and 40-percent non-spinning reserves to comply with WECC spinning and non-spinning reserve requirements.[51] An additional 14 percent incremental operating reserve

[51] At least half of the operating reserves must be Spinning Reserve. Spinning reserve is the margin of generating capacity available to replace lost capacity and provide the regulating margin to follow load; spinning capacity must

requirement is applied against nameplate wind capacity (211 MW) to cover incremental operating reserves for wind as determined by PacifiCorp's 2010 wind integration study.

The operating reserve modeling approach does not address the impact of resource type (i.e., hydro, wind, or thermal) in determining required operating reserves. Operating reserves count toward the PRM, but the required percentages for the Balancing Authority Areas (8.6 percent and 8.1 percent) stay constant regardless of resource mix.

All Balancing Authorities within the Northwest Power Pool are also required to participate in the Contingency Reserve Sharing Program. This program provides 60-minute recovery assistance following the loss of a generating resource or transmission path, or failure of a generating unit to start up or increase output. This assistance is provided after the Balancing Authority uses up its Contingency Reserve Obligation (i.e., 7 percent of load served by thermal resources; 5 percent of load served by hydro reserves). The reserve sharing program provides a benefit to the utility by covering the first hour of an outage. For recording LOLH and calculating LOLP, the stochastic simulation should omit the first hour of a forced outage event in order to capture reserve sharing benefits. Implementing this functionality in the PaR model requires that a "shadow" station be assigned to each unit with a capacity equal to the unit MW rating and energy equal to the full load output. The shadow station is called upon in the event of a unit outage, thereby contributing emergency generation for one hour during the outage period. (The PaR model would determine that hour based on the marginal energy cost during the outage period.)

This modeling approach was judged to be too complex to implement and validate in time for use in the 2011 IRP. However, this approach was implemented for a loss of load study conducted by the PaR model vendor, Ventyx LLC, for Public Service Company of Colorado. The impact to the PRM of modeling reserve sharing rules of the Rocky Mountain Reserve Group (RMRG) was a reduction of 1.5 percentage points.[52] While the RMRG reserve sharing rules provide for up to two hours of contingency reserve assistance as opposed to the one hour for the Northwest Power Pool's program, the RMRG rules are more restrictive in other respects. For example, reserve support is targeted for units at least 200 MW in size, is provided only to the unit with the largest capacity in the event that two or more units experience simultaneous outages, covers only one outage event per month, and covers less than the full unit capacity due to a smaller pool of member reserves available. Given these offsetting limitations, PacifiCorp assumes that a PRM reduction of 1.5 percentage points is a reasonable proxy for the NWPP's reserve sharing benefit.

Study Results

Figure J.10 reports the LOLH counts for the five PRM levels modeled, while Figure J.11 reports the resulting LOLE index values (the stochastic average for the 100 Monte Carlo iterations).

be synchronized to the system and ready to provide power instantaneously. Non-spinning reserve is generating capacity that is not synchronized to the system but can be available within a few hours – although some capacity may be ready immediately.

[52] The loss of load report is available at:
http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPReserveMarginStudy.pdf

Fitted curves highlight the smooth relationship between the reliability statistics and the PRM level.

Figure J.12 reports the total fixed cost of meeting each PRM level based on the incremental IC aero SCCT resource capacity required. The per-unit fixed cost is approximately $191/kW-year, which is grossed up to account for a 2.7 percent expected forced outage rate. Each percentage point increase in the PRM translates into an incremental fixed cost of about $42 million.

Figure J.10 – System LOLH by Planning Reserve Margin Level

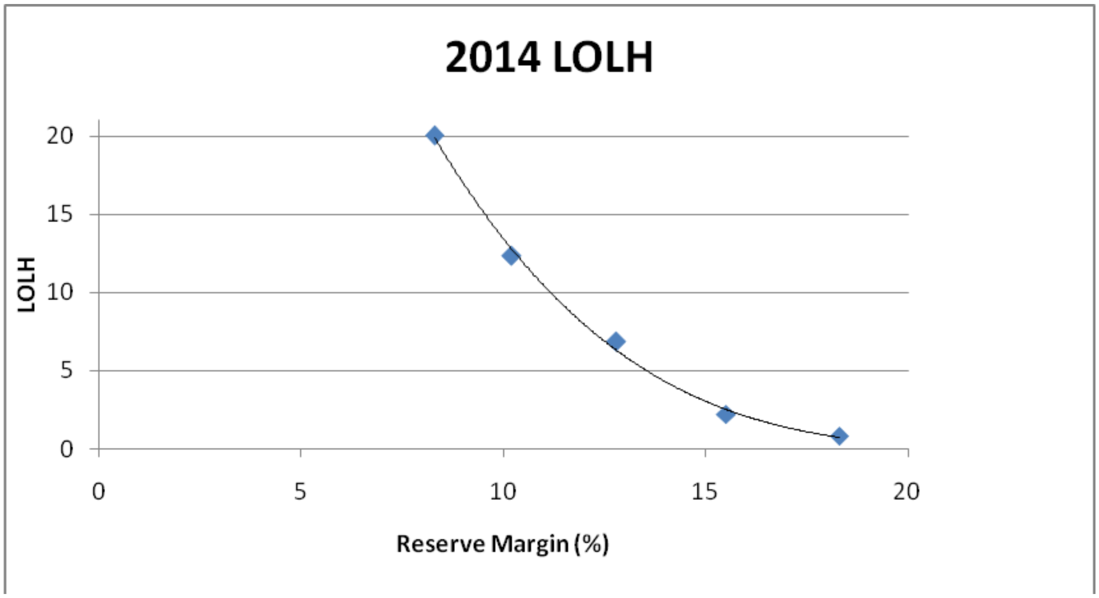


Figure J.11 – System LOLP Index by Planning Reserve Margin Level

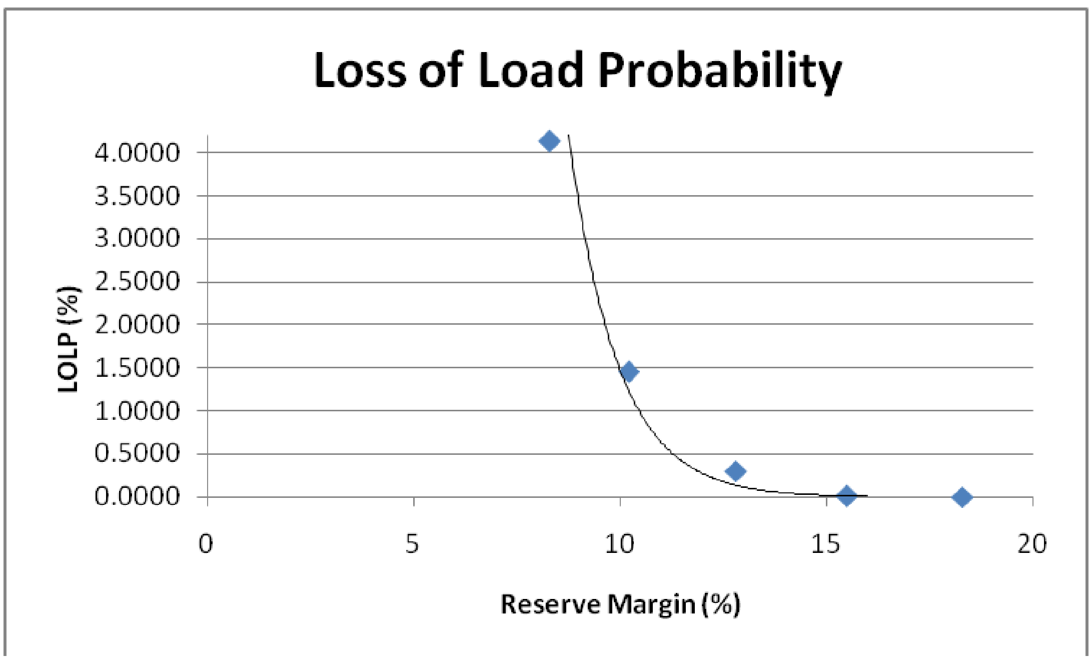
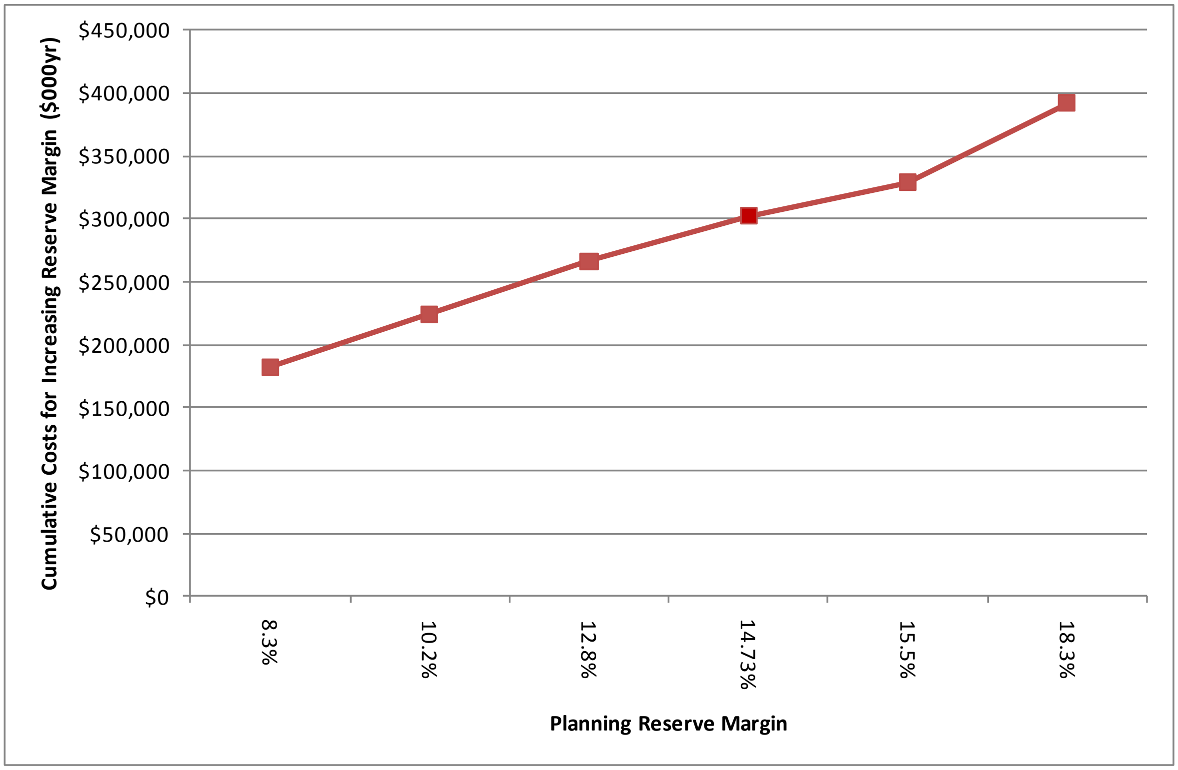


Figure J.12 – Reliability Resource Fixed Costs Associated with Meeting PRM Levels

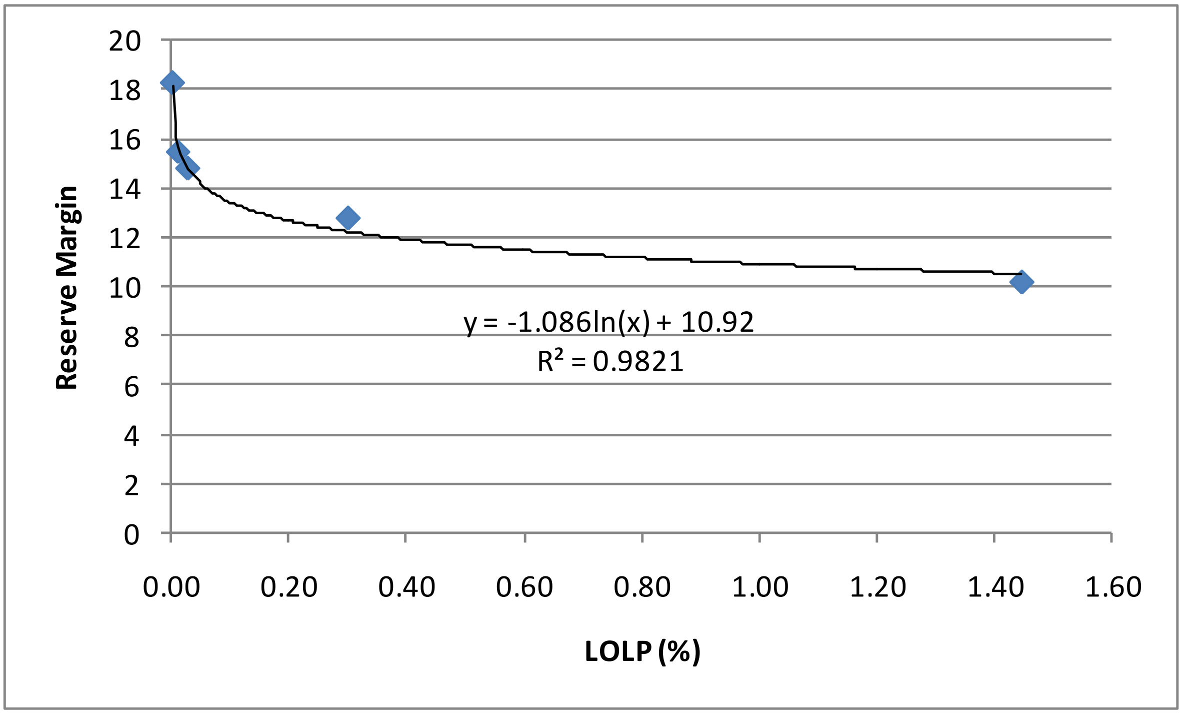


SELECTION OF A LOLP RELIABILITY TARGET

Traditionally, the long-term reliability planning standard has been a one-day in ten year loss of load criterion: 24 hours / (8760 hours x 10 years) = 0.027 percent. PacifiCorp has thus adopted this standard for determination of its PRM for IRP portfolio development.[53] Using a logarithmic functional form and regressing the PRM levels against the LOLE values, yielded a PRM of 14.8 percent to achieve a one-day in ten year loss of load (Figure J.13).

[53] Reliance on a one-in-ten loss of load criterion is being bolstered at the Federal level. The Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking in October 2010 approving a regional resource adequacy standard for Reliability*First* Corporation (RFC) based on a one-in-ten loss of load criterion. RFC is one of the nine North American Electric Reliability Corporation's electricity reliability councils, consisting of the former Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN).

Figure J.13 – Relationship between Reserve Margin and LOLP



Capacity Planning Reserve Margin Determination

As noted previously, the loss of load study does not incorporate the benefit of the Northwest Power Pool reserve sharing program. As a result, the 14.8 percent PRM requires a downward adjustment. Applying the 1.5 percent RMRG reserve sharing impact estimated by Ventyx for Public Service Company of Colorado results in an adjusted PRM of 13.3 percent. Rounding to 13 percent yields the PRM that PacifiCorp selected for its 2011 IRP portfolio development.

Conclusion

Based on the loss of load study and an out-of-model planning reserve margin adjustment to reflect reliability benefits from the Northwest Power Pool's reserve sharing program, PacifiCorp selected a 13% PRM for 2011 IRP portfolio development. PacifiCorp's previous PRM was 12 percent. This study incorporated a one-year snapshot of the transmission topology and loads & resources situation, targeting 2014 as the representative study year. Since the study focused on the PRM needed to meet firm load and sales obligations, it did not incorporate the reliability benefits of accessing off-system generation with non-firm transmission capacity.

PacifiCorp evaluated the reliability impact of different resource mixes using LOLP and Energy Not Served measures as part of its portfolio evaluation process.

APPENDIX K – HYDROELECTRIC CAPACITY ACCOUNTING

Introduction

The Utah Commission, in its 2008 IRP acknowledgment order, directed the Company to revisit its approach for estimating the capacity contribution of hydroelectric facilities for load & resource balance development purposes. Both the Utah Division of Public Utilities and Office of Consumer Services specifically recommended in their written comments on the 2008 IRP that the Company continue to investigate the hydro capacity accounting methodology adopted for regional resource adequacy reporting purposes by the Pacific Northwest Resource Adequacy Forum, an organization sponsored by the Northwest Power and Conservation Council (NWPCC). This accounting methodology extends the one-hour sustained peaking period to the six highest load hours over three consecutive days of highest demand. The methodology was originally adopted in 2008, and continues to be investigated and refined.

In this appendix, the Company first describes what hydro facilities are eligible for providing sustained hydro peaking capability under an 18-hour standard, and then reports its estimates of the 18-hour sustained hydro capability for the eligible facilities. The Company then discusses the applicability of this standard to PacifiCorp's hydroelectric system.

Eligible Sustained Peaking Hydro Facilities

PacifiCorp evaluated its hydro resource portfolio according to the definitions and methodologies outlined by the current standards established by the Pacific Northwest Resource Adequacy Forum. The following PacifiCorp hydroelectric facilities apply with regard to supporting sustained capacity for the Northwest:

Lewis River

- Swift-1
- Swift-2
- Yale

Other hydro facilities owned and operated by PacifiCorp that provide limited peaking

- JC Boyle
- Copco-1
- Copco -2
- Lemolo -1
- Lemolo- 2
- Toketee
- Slide Creek
- Oneida

- Cutler

This second group of hydro facilities was determined to be ineligible for providing sustained peaking capability as defined by the Pacific Northwest Resource Adequacy Forum. For example, they lack sufficient storage for sustained peaking and are constrained in their dispatch by minimal inflow during the peak load period (July), have ramping regulations imposed within the operating license, restrictive minimum flow regulation and stage change downstream of the project, irrigation priority, and fisheries/recreation requirements. Only the Lewis River facilities listed above (Swift-1, Swift-2, and Yale) meet the criteria for providing 18-hour sustained peaking capability without extraordinary actions taken regarding adaptive policy decisions or waivers by the various governing agencies and primary stakeholders of the project output.

Sustained Hydro Peaking Capability for Lewis River Facilities

During the July peak load period, the Swift and Yale reservoirs are maintained near full pool elevation in support of recreation. Historical median flow into the Swift reservoir in July is 1245-cubic feet per second (cfs). The median natural accretion between Swift and Yale reservoirs is 198 cfs. The median natural accretion between Yale and Merwin reservoirs is 198 cfs. Minimum flow below the re-regulating facility downstream of Swift and Yale, varies during the month of July from 2,300 cfs in the first ten days, 1900 cfs in the second ten days, and 1,500 cfs in the last ten days of the month. From July 31st to mid October, the minimum flow is 1,200 cfs. In a median water year, Swift and Yale reservoirs operate in the upper eight feet of the reservoir 100 percent of the time in July. Over a 15-year consecutive period, Swift and Yale reservoirs operate in the upper eight feet of the reservoir 93 percent of the time in July. In the upper eight feet of the reservoirs, Swift 1 and 2 and Yale are capable of 344 MW and 134 MW, respectively. The maximum sustained peak capacity for Swift 1 and 2 combined is 210 MW. At Yale, the maximum sustained peak capacity is 95 megawatts. The total combined sustained peak capacity is therefore 304 MW. The difference between the one-hour sustained peaking capacity and 18-hour sustained peaking capacity is a reduction of 164 MW as indicated in Table

Table K.1 – Peaking Capability Comparison for Lewis River Hydro Facilities

Unit	One-hour Sustained Peaking Capability (MW)	18-hour Sustained Peaking Capability Capacity (MW)	Difference (MW)
Swift 1 and 2	319	210	(109)
Yale	150	95	(55)
TOTAL	**469**	**305**	**(164)**

These estimates were determined assuming the critical event occurs in the first ten days of July when the minimum stream flow requirement is the highest. Given the median inflows and assuming the same 18-hour sustained peaking period, the available peak flow for Swift 1 and 2 is 5,000 cfs, whereas the peak flow for Yale is 5,800 cfs. The above stated sustained capacity pertains to these peak period flows. Under peak operation, reservoir levels remain approximately constant as normally required to support recreation.

Applicability of an 18-hour Sustained Peaking Capability Standard for PacifiCorp

The Pacific Northwest Resource Adequacy Forum's 18-hour sustained peaking period standard is intended as a broad regional capacity planning guideline. The issue is whether it makes sense to adopt for PacifiCorp based on its hydro licensing provisions and operational protocols and practices. In practice, the Company would not adhere to reservoir level compliance or constant stream flow regulation below Merwin if there was an emergency need for generation to support critical load. In a real world situation, PacifiCorp would generate to maximum capacity of the units and make the necessary public announcements unless instructed to provide the sustained capacity per a revised peaking period definition enforced by the Western Electric Coordinating Council or Northwest Power Pool.

Conclusion

The Company has the ability to operate outside the normal boundaries of the operating license given emergency conditions, which means that the 18-hour sustained peaking standard would not be relevant for peak capacity planning as it relates to PacifiCorp's hydro system. Additionally, the choice of the length of the sustained peaking period has minimal consequences for capacity position reporting given that the sustained peaking period must be consistently applied to both hydro capacity and peak loads.

It is also important to note that the NWPPC characterizes the Resource Adequacy Forum's capacity adequacy standard as being useful for informing hydro utilities' resource planning efforts, and not as a methodology that should be adopted in lieu of the utilities' own planning criteria and methodologies.

APPENDIX L – PLANT WATER CONSUMPTION

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

Table L.1 – Plant Water Consumption with Acre-Feet Per Year

			Acre-Feet Per Year					MWhs Per Year					
PLANT NAME	**Discharge Permit?**	**Consumption net of Discharge?**	**2007**	**2008**	**2009**	**2010**	**Average**	**2007**	**2008**	**2009**	**2010**	**Gals/ MWH**	**GPM/ MWh**
Carbon	Yes	No	2,380	2,199	2,349	2,193	2,280	1,339,343	1,204,982	1,211,875	1,296,004	588	9.8
Chehalis*	Yes	Yes					-			1,747,252	1,288,256	-	0.0
Currant Creek*	Zero Discharge	Does not apply	116	82	108	83	97	3,605,071	2,799,585	2,464,463	2,536,660	11.1	0.2
Dave Johnston	Yes	No	7,872	7,746	6,983	6,604	7,301	5,696,860	5,638,806	5,017,796	4,699,767	452	7.5
Gadsby**	Yes	No	778	426	680	893	694	633,049	482,596	605,817	359,404	435	7.2
Hunter	Zero Discharge	Does not apply	19,157	19,380	19,300	19,200	19,259	9,600,295	10,246,965	9,438,683	8,785,827	659	11.0
Huntington	Zero Discharge	Does not apply	11,737	11,385	10,922	9,566	10,903	7,127,084	7,148,850	6,753,764	6,107,379	524	8.7
Jim Bridger	Zero Discharge	Does not apply	25,616	27,322	25,361	24,076	25,594	15,119,379	15,303,508	15,188,184	14,828,906	552	9.2
Lakeside***	Yes	Yes	0	1,821	1,287	1,533	1,160	0	2,861,722	2,099,109	2,537,046	202	3.4
Naughton	Yes	No	9,948	10,992	10,846	0	7,947	5,210,618	5,114,409	4,752,632	5,339,603	687	11.4
Wyodak*	Zero Discharge	Does not apply	405	446	365	396.00	403	2,862,771	2,811,590	2,716,055	2,565,341	47	0.8
TOTAL			**78,009**	**81,799**	**78,201**	**64,543**	**79,336**	**51,194,470**	**53,613,013**	**51,995,630**	**50,344,193**	**476**	**7.9**

* Equipped with air cooled condenser

**Mix of both rankine steam units and peaking gas turbines

*** First full year of water consumption occurred in 2008

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

Table L.2 – Plant Water Consumption by State

UTAH PLANTS			
PLANT NAME	**2007**	**2008**	**2009**
Hunter	19,157	19,380	19,300
Huntington	11,737	11,385	10,922
Carbon	2,380	2,199	2,349
Currant Creek	116	82	108
Lakeside	-	1,821	1,287
Gadsby	778	426	680
TOTAL	**34,168**	**35,293**	**34,646**

Percent of total water consumption = 43.7%

WYOMING PLANTS			
PLANT NAME	**2007**	**2008**	**2009**
Naughton	9,948	10,992	10,846
Jim Bridger	25,616	27,322	25,361
Wyodak	405	446	365
Dave Johnston	7,872	7,746	6,983
TOTAL	**43,841**	**46,506**	**43,555**

Percent of total water consumption = 56.3%

Table L.3 – Plant Water Consumption by Fuel Type

COAL FIRED PLANTS			
PLANT NAME	**2007**	**2008**	**2009**
Hunter	19,157	19,380	19,300
Huntington	11,737	11,385	10,922
Carbon	2,380	2,199	2,349
Naughton	9,948	10,992	10,846
Jim Bridger	25,616	27,322	25,361
Wyodak	405	446	365
Dave Johnston	7,872	7,746	6,983
TOTAL	**77,115**	**79,470**	**76,126**

Percent of total water consumption = 97.8%

Generation Capacity (MW)	**Ac-ft/MW**
1320	14.6
895	12.7
175	13.2
700	15.1
2120	12.3
335	1.2
762	9.9
Average	**11.3**

NATURAL GAS FIRED PLANTS					
PLANT NAME	**2007**	**2008**	**2009**	**Generation Capacity (MW)**	**Ac-ft/MW**
Currant Creek	116	82	108	523	0.2
Lakeside	-	1,821	1,287	575	2.7
Gadsby	778	426	680	235	2.7
TOTAL	**894**	**2,329**	**2,075**	**Average**	**1.9**

Percent of total water consumption = 2.2%

Table L.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin

PLANT NAME	2007	2008	2009
Hunter	19,157	19,380	19,300
Huntington	11,737	11,385	10,922
Carbon	2,380	2,199	2,349
Naughton	9,948	10,992	10,846
Jim Bridger	25,616	27,322	25,361
TOTAL	**68,838**	**71,278**	**68,778**

Percent of total water consumption = 87.8%