PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 30, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attn: Filing Center

RE: PacifiCorp's 2013 Integrated Resource Plan

Please find enclosed an original and five copies of PacifiCorp's 2013 Integrated Resource Plan (2013 IRP). The 2013 IRP is also available electronically on PacifiCorp's IRP website, at http://www.pacificorp.com/es/irp.html. Confidential information is provided in accordance with the protective order to this docket, Order No. 13-095.

PacifiCorp submits the 2013 IRP to the Oregon Public Utility Commission (Commission) under OAR 860-027-0400. The 2013 IRP contains information outlining how PacifiCorp has addressed each of the procedural and substantive elements of the Commission's rules (see Tables B.2 and B.3, in "Appendix B – IRP Regulatory Compliance").

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PacifiCorp appreciates the time and effort Oregon participants have dedicated to helping the Company develop its 2013 IRP.

Informal inquiries may be directed to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement at (503) 813-6389.

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

cc: Service List LC 52 (without enclosures)
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I certify that I served a true and correct copy of PacifiCorp's 2013 Integrated Resource Plan on the parties listed below via electronic mail and/or Overnight Delivery in compliance with OAR 860-001-0180.

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2013

Integrated Resource Plan

Volume I

Let's turn the answers on.

April 30, 2013

PacifiCorp

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

This 2013 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Transmission: *Sigurd to Red Butte Transmission Segment G*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Wind Turbine: *Leaning Juniper I Wind Project*
Thermal-Gas: *Chehalis Power Plant*
Solar: *Black Cap Photovoltaic Solar Project*

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2013 Integrated Resource Plan (2013 IRP), representing the 12th plan submitted to state regulatory commissions, presents a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks to its customers. It was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties.

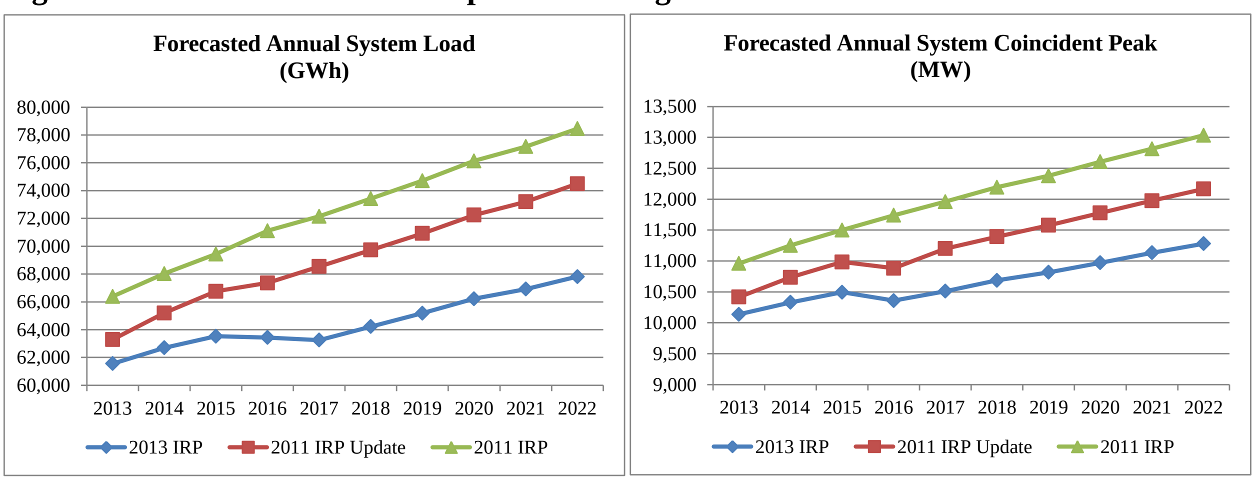
The key elements of the 2013 IRP include (1) a finding of resource need, focusing on the 10-year period 2013-2022, (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need, and (3) an action plan that identifies the steps the Company will take during the next two to four years to implement the plan. The process and outcome of the IRP—the preferred portfolio and action plans—meet applicable state IRP standards and guidelines. PacifiCorp continues to plan on a system-wide basis while accommodating state resource acquisition mandates and policies.

2013 IRP Highlights

Development of the 2013 IRP involved balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. Key drivers to the 2013 IRP preferred portfolio and associated action plan include the following:

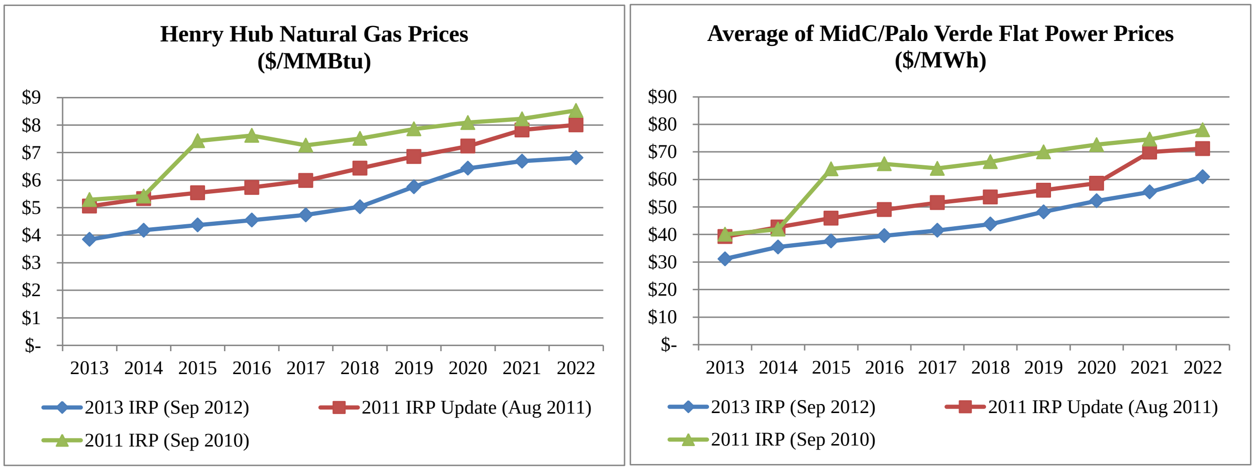
- As shown in Figure ES.1, the Company's load forecast in the 2013 IRP is down in relation to projected loads used in the 2011 IRP and 2011 IRP Update. The lower load forecast is driven significantly by industrial self generation taking advantage of low natural gas prices, as well as by load request cancellations in Utah and Wyoming and postponements prompted by prolonged recessionary impacts and permitting issues. The reduced load forecast has greatly mitigated, but not eliminated the need for resources in the front ten years of the planning horizon, and is a significant driver in resource portfolio modeling performed for the 2013 IRP.

Figure ES.1 – Load Forecast Comparison among Recent IRPs



- Figure ES.2 shows that base case wholesale power prices and natural gas prices used in the 2013 IRP are significantly lower than the base case market prices used in the 2011 IRP and 2011 IRP Update. The decline in forward natural gas prices has largely been influenced by continued growth in prolific shale gas plays in North America. With continued declines in natural gas prices and reduced regional loads, forward power prices have also declined significantly over the past two years. Given these favorable market conditions, front office transactions play a critical role in meeting coincident peak loads throughout the front ten years of the planning horizon.

Figure ES.2 – Power and Natural Gas Price Comparison among Recent IRPs



- In all portfolios evaluated in the 2013 IRP, energy efficiency resources play an important role in meeting load growth throughout the front ten years of the planning horizon. In the 2013 IRP preferred portfolio, the accumulated acquisition of incremental energy efficiency resources meets 67 percent of currently forecasted load growth from 2013 levels by 2022, and the 2013 IRP action plan identifies steps the Company will take in the next two to four years to accelerate acquisition of cost-effective energy efficiency resources.

- Policy and market developments have contributed to higher renewable resource costs and reduced benefits. On the policy front, policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise, making the long-term outlook for federal tax incentives that have traditionally benefited new renewable resources highly uncertain. Policy makers have also not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not finalized those standards, nor has it established a schedule to promulgate rules applicable to existing sources. With higher after-tax costs, lower power prices, and continued greenhouse gas regulation uncertainty, the need for new renewable resources will be driven by state-specific renewable portfolio standard (RPS) regulations. To mitigate the cost of RPS compliance, analyses in the 2013 IRP supports the use of unbundled renewable energy credits (RECs) to meet state RPS obligations through the first ten years of the planning period.

- On March 15, 2013, the Utah Public Service Commission approved the Company's application for a Certificate of Public Convenience and Necessity (CPCN) for the Sigurd to Red Butte transmission project. The Company began construction of the Sigurd to Red Butte transmission project in April, 2013 with a scheduled in-service date of June, 2015. For the 2013 IRP, the Company has completed preliminary analysis of the Windstar to Populus transmission project (Energy Gateway Segment D) that supports on-going permitting activities. Permitting activities for other Energy Gateway transmission segments will continue in parallel with the on-going development of analytical tools that can be used to evaluate transmission benefits that are not traditionally captured in the resource portfolio modeling process used in the IRP.

- The Company has analyzed in the 2013 IRP environmental investments required to meet known and prospective compliance obligations across PacifiCorp's existing coal fleet. Supported by analyses performed as part of the 2013 IRP and analyses performed in recent regulatory filings, the Company plans to convert Naughton Unit 3 to a natural gas-fired facility and to install environmental investments required to meet near term compliance obligations at the Hunter Unit 1, Jim Bridger Unit 3, and Jim Bridger Unit 4 generating units. Installation of emission control equipment at these facilities will reduce emissions of nitrous oxides (NO_X) and sulfur dioxide (SO_2) and contribute to improved visibility in the region. The Company plans to continue to evaluate environmental investments required to meet known and prospective environmental compliance obligations at existing coal units in future IRPs and future IRP Updates.

Modeling and Process Improvements

In developing the 2013 IRP, the Company has significantly advanced its analytical methods and portfolio development approach. The notable improvements that are summarized below have very much influenced the 2013 IRP and establish a sound foundation for analysis in future IRPs.

- Energy Gateway Transmission

  In contrast to the 2011 IRP, where analysis of Energy Gateway transmission investments preceded resource portfolio modeling, Energy Gateway transmission investments have been integrated into the portfolio modeling process for the 2013 IRP. This was achieved by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. Consequently, 94 unique core case resource portfolios were produced in the 2013 IRP, nearly five times the number of core case portfolios developed for the 2011 IRP.

  In addition to incorporating Energy Gateway transmission investments into the resource portfolio modeling process, the 2013 IRP introduces the System Operational and Reliability Benefits Tool (SBT), which identifies and quantifies transmission benefits that are not captured using production cost dispatch models traditionally used for IRP analyses. In this way, the SBT identifies, measures, and monetizes benefits that are incremental to those identified in the resource portfolio modeling process. Analysis using the SBT supports investment in the Sigurd to Red Butte transmission project and preliminary application of the SBT to the Windstar to Populus transmission project supports continued permitting of Energy Gateway Segment D. The SBT will continue to be developed and will be applied to additional Energy Gateway transmission projects for analysis in future IRPs.

- Existing Coal Resources

  Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process in the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations tied to Regional Haze rules, Mercury and Air Toxics Standards (MATS), regulation of coal combustion residuals (CCR), and regulation of cooling water intakes are considered in the development of *all* resource portfolios developed for the 2013 IRP. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. In addition to integrating coal unit environmental investment decisions into the portfolio development process, the Company has completed detailed financial analysis of near-term investment decisions in Confidential Volume III of the 2013 IRP.

- Energy Efficiency

  PacifiCorp continues to evaluate energy efficiency as a resource that competes with traditional supply-side resource alternatives when developing resource portfolios that are compared under a range of cost and risk metrics. The 2013 IRP includes for the first time core case resource portfolios developed assuming accelerated acquisition of energy efficiency resources. While the assumptions developed for these cases require further validation and review, cost and risk analysis of these portfolios have led to action items in the 2013 IRP action plan to accelerate acquisition of cost-effective energy efficiency resources.

  In addition to evaluating acceleration of energy efficiency resources in the 2013 IRP, the Company greatly expanded its representation of energy efficiency resource attributes that influence selection in any given portfolio. Energy efficiency resources were modeled with additional cost granularity by increasing the number of cost steps that delineate groupings of different energy efficiency measures. In the 2011 IRP, energy efficiency resources for a given state were grouped into nine different cost levels, whereas the 2013 IRP modeling was performed using 27 different cost levels to represent energy efficiency resource opportunities in each state. Implementation of this modeling refinement deteriorated model performance, and the Company has developed an action item to study trade-offs between resource selections and model run-times at different levels of granularity.

- Renewable Portfolio Standards

  The 2013 IRP includes portfolios with and without renewable portfolio standard (RPS) requirements to isolate how system costs and portfolio risks are affected when new renewable resources are added to a portfolio for the sole purpose of meeting state-specific RPS compliance targets. In those cases where RPS compliance targets are assumed and incremental renewable resources are needed for the sole purpose of achieving RPS targets, the RPS Scenario Maker model was introduced into the 2013 IRP. The RPS Scenario Maker model was used to establish a minimum level of new renewable resources needed to meet RPS compliance targets while considering compliance flexibility mechanisms such as "banking" unique to each state RPS program.

- Public Process

  The involvement of stakeholders is a critical element of the IRP process. Over the course of developing the 2013 IRP, the Company expanded its open and collaborative approach to resource planning by increasing opportunities for stakeholder participation. The Company hosted 15 public input meetings, more than twice the number of public input meetings held for the 2011 IRP, supplemented communications with stakeholder conference calls, and held five state meetings. In addition, the Company made available to stakeholders a website used to provide data and to communicate Company responses to stakeholder questions received throughout the public process.

Resource Need

PacifiCorp's need for new resources is determined by developing a capacity load and resource balance that considers the coincident system peak load hour capacity contribution of existing resources, forecasted loads and sales, and reserve requirements. For capacity expansion planning, the Company uses a 13 percent planning reserve margin, which is applied to PacifiCorp's obligation net of offsetting "load resources" such as dispatchable load control capacity.[1]

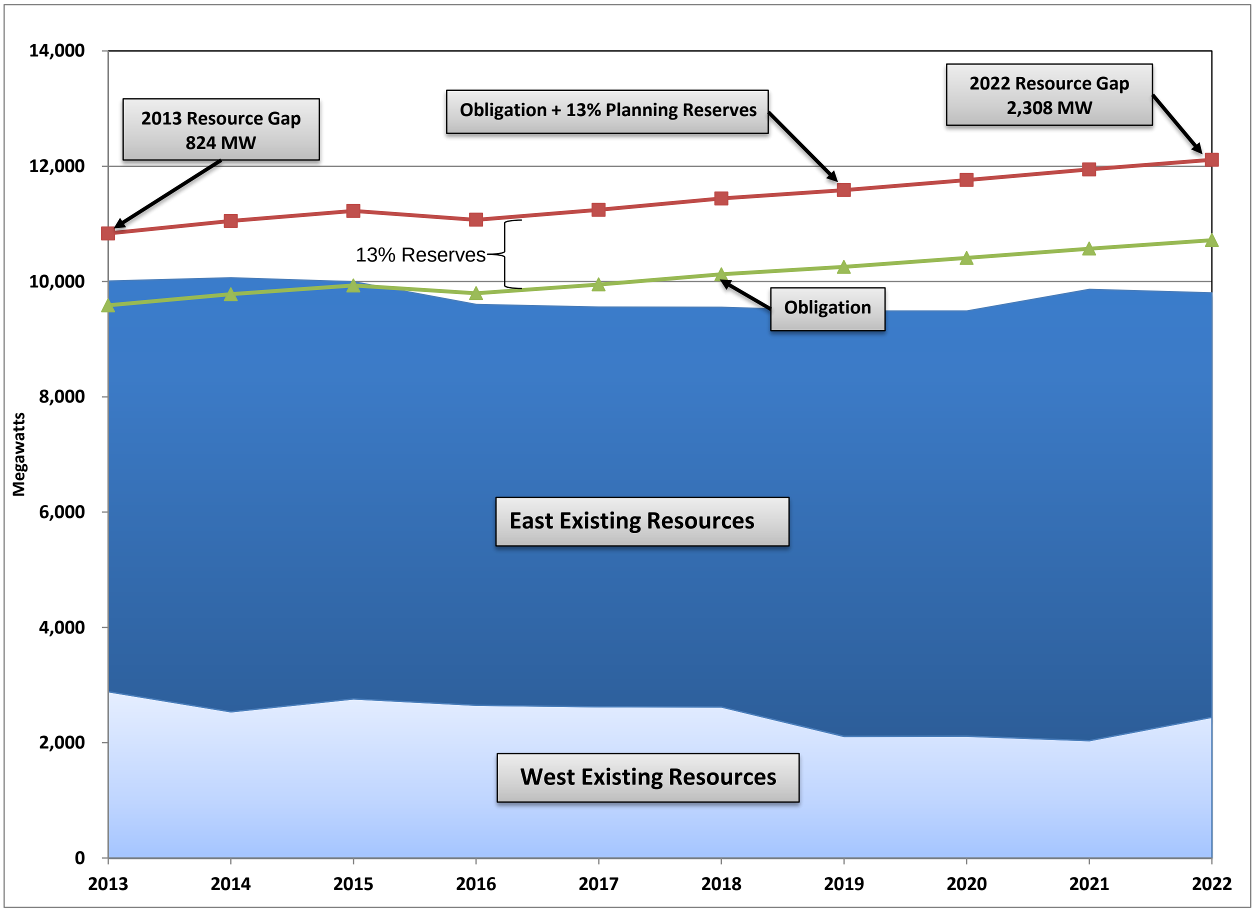
Table ES.1 shows the Company's annual capacity position for 2013 through 2022, and Figure ES.3 graphically highlights the capacity resource gap in relation to currently owned and contracted east and west-side resources. Without new resources, the system experiences a capacity deficit of 824 megawatts in 2013, down by 57 percent as compared to the 2011 IRP and down by 39 percent as compared to the 2011 IRP Update. By 2022, the system capacity deficit reaches 2,308 megawatts. Over the 2013 to 2022 timeframe, the system peak load is forecasted to grow at a compounded annual rate of 1.2 percent (prior to forecasted load reductions from energy efficiency). On an energy basis, PacifiCorp expects system-wide average load growth of 1.1 percent per year.

Table ES.1 – PacifiCorp 10-year Capacity Position Forecast (Megawatts)

System	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves (Based on 13% Target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + 13% Planning Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

[1]The 13 percent planning reserve margin is supported by a stochastic loss of load probability study that is summarized in Volume II, Appendix I of the 2013 IRP.

Figure ES.3 – PacifiCorp Capacity Resource Gap



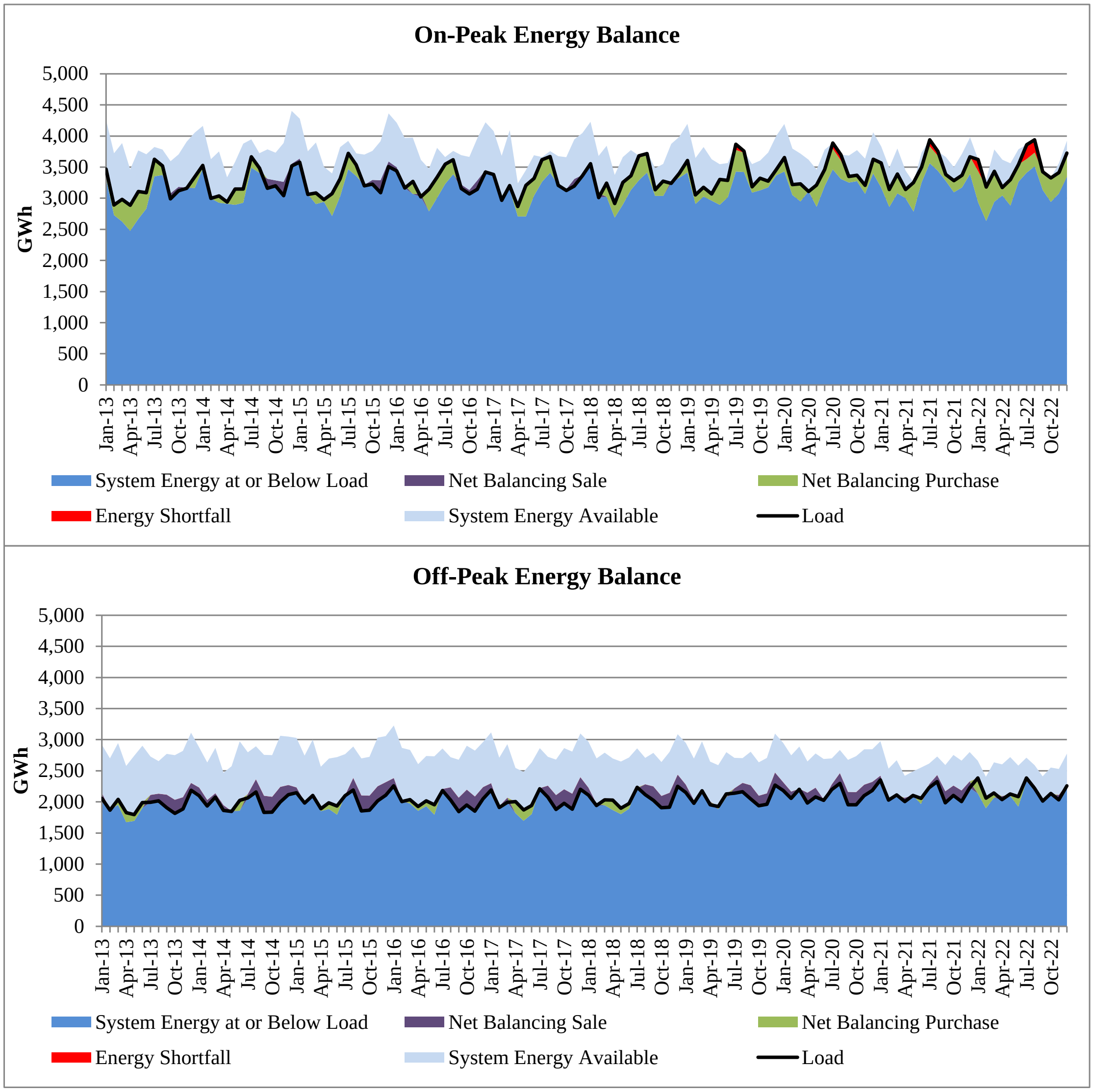
The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, the Company economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, the Company can dispatch resources that in aggregate exceed then-current load obligations, facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs.

Figure ES.4 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and current wholesale power and natural gas prices.[2] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load assuming no additional resources are added to PacifiCorp's system. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak

[2] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

periods. Figure ES.4 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018, and by 2022 available system energy falls short of monthly loads in January, July, August, and October. During off-peak periods, there are no energy shortfalls through the 2022 timeframe.

Figure ES.4 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



Future Resource Options and Portfolio Modeling

In line with state IRP standards and guidelines, PacifiCorp included a wide variety of resource options in portfolio modeling covering generation, demand-side management and transmission. Cost and performance assumptions for resource alternatives were developed using multiple sources, including: third party estimates, data from actual and projected PacifiCorp or utility industry installations, and data from recent request for proposals and requests for information. Table ES.2 summarizes the wide range of resource alternatives evaluated in the 2013 IRP.

Table ES.2 – 2013 IRP Resource Options*

Natural Gas	Other Thermal	Renewable	Energy Storage	Distributed Generation	Class 1 DSM (Direct Load Control)	Class 2 DSM (Energy Efficiency)	Class 3 DSM (Demand Response)
▪ SCCT Aero ▪ Intercooled SCCT Aero ▪ SCCT Frame ▪ IC Recip. Engine ▪ CCCT (2x1) F-class ▪ CCCT (2x1) G/H-class ▪ CCCT (1x1) G/H-class ▪ CCCT (1x1) J-class ▪ CCCTs with and without duct firing	▪ IGCC with carbon capture and sequestration ▪ Nuclear fission	▪ Geothermal (PPAs) ▪ Wind ▪ Solar PV (fixed tilt & tracking) ▪ Biomass	▪ Pumped Storage ▪ Sodium-Sulfur Battery ▪ Advanced Fly Wheel ▪ Compressed Air Energy Storage	▪ Reciprocating Engines ▪ Gas Turbine ▪ Microturbine ▪ Fuel Cell ▪ Commercial Biomass, Anaerobic Digester ▪ Industrial Biomass, Waste ▪ Rooftop Solar PV ▪ Solar Water Heaters	▪ Residential Central Air & Water Heating ▪ Small Commercial Central Air & Water Heating ▪ Irrigation Load Curtailment ▪ Commercial Curtailment ▪ Industrial Curtailment	▪ Residential, Commercial, Industrial, Irrigation, and Street Lighting Measures ▪ 27 measure bundles grouped by cost among five states ▪ Energy Trust of Oregon Energy Efficiency Measures as Applicable for Oregon	▪ Residential time-of-use rates ▪ Commercial Critical Peak Pricing ▪ Commercial and Industrial Demand Buyback ▪ Voluntary Irrigation Time-of-Use

*SCCT = simple cycle combustion turbine; CCCT = combined cycle combustion turbine; IGCC = integrated gasification combined cycle, PPA = power purchase agreement; PV = photo voltaic, DSM = demand side management

PacifiCorp's IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios, and consists of eight phases:

- Define input scenarios for portfolio development
- Price forecast development (natural gas and wholesale electricity by market hub)
- Optimize portfolio development using PacifiCorp's *System Optimizer* capacity expansion model for cases without RPS requirements
- Develop a renewable resource floor, reflecting renewable resource additions chosen in optimized portfolios from cases that exclude RPS requirements needed to achieve compliance for cases that do include RPS assumptions
- Optimize portfolio development using PacifiCorp's *System Optimizer* capacity expansion model for cases with RPS requirements
- Stochastic Monte Carlo production cost simulation of optimized portfolios
- Selection of top-performing portfolios using a three-phase screening process that incorporates stochastic portfolio cost and risk assessment measures
- Preliminary preferred portfolio selection, followed by additional analysis and determination of the final preferred portfolio

PacifiCorp worked with stakeholders to define 19 input scenarios, or "core cases", which were applied across five different Energy Gateway transmission scenarios totaling 94 different variations of resource portfolios.[3] The 19 different core cases were categorized into four different themes:

(1) Reference: There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.

(2) Environmental Policy: There are 11 different core cases developed for the Environmental Policy Theme. Five of the 11 cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO_2 prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency.

(3) Targeted Resources: There are four different core cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four cases prevents combined cycle resources from being added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four cases in this theme assumes a spike in power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth case in this theme targets clean energy resources and assumes CO_2 prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.

(4) Transmission: The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to the Company's Gateway Segment D project. This case was only analyzed in four of the five Energy Gateway scenarios that include the Gateway Segment D project.

PacifiCorp selected top-performing portfolios on the basis of system costs using Monte Carlo simulations of each portfolio over a twenty year planning horizon. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability. The relative average cost among portfolios and the upper tail cost among portfolios are used to evaluate cost and risk metrics among candidate portfolios and are used to identify top performing resource portfolios that inform the Company's selection of the preferred

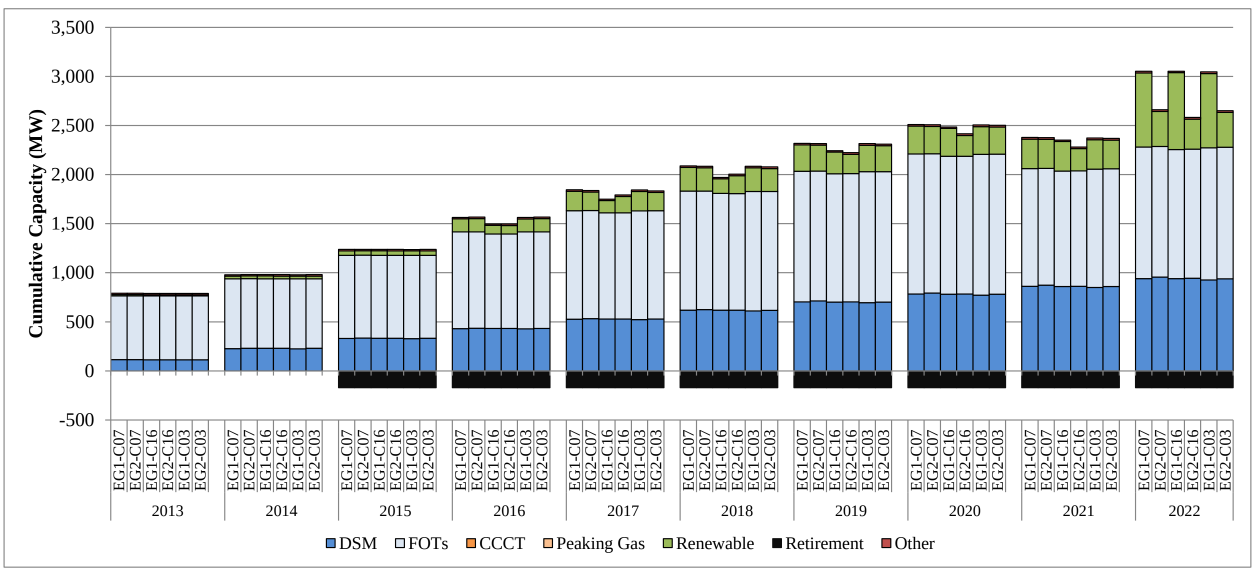
[3] One of the input scenarios is applicable to four out of the five Energy Gateway transmission scenarios.

portfolio. In making its preferred portfolio selection, the Company considers measures of risk-adjusted portfolio costs, customer rate impacts, CO_2 emissions, and supply reliability.

In the 2013 IRP, some portfolios developed under the assumption that acquisition of demand side management (DSM) resources can be accelerated performed well on a risk adjusted cost basis. However, given uncertainties in incentive and administrative costs and delivery risks associated with accelerating acquisition of DSM resources, these portfolios were not selected as the preferred portfolio. Nonetheless, the potential benefits of accelerating acquisition of DSM resources has prompted the Company to develop action items in 2013 IRP Action Plan targeting accelerated acquisition of cost effective DSM resources.

Figure ES.5 summarizes the nameplate capacity of cumulative resource selections through 2022 among top performing portfolios developed under base case DSM acquisition ramp rate assumptions. With reduced load expectations and market prices, resource selections among the top performing portfolios over the first 10 years of the planning horizon are dominated by energy efficiency and front office transaction (FOT) resources, and there are no new CCCT resources required over this timeframe. Among these cases, renewable resources are added in different quantities and at different times for the sole purpose of meeting west side state RPS requirements. The variability in quantity, type, and timing of new renewable resources is dependent on whether the Windstar to Populus transmission project is built.

Figure ES.5 – Comparison of Resource Types in Top Performing Portfolios



In the final screening stage of the 2013 IRP portfolio analysis, the Company evaluated an alternative strategy to meet Washington RPS requirements with unbundled RECs. This analysis shows that a compliance strategy focused on acquiring unbundled RECs is favorable on a cost and risk basis, and supports 2013 IRP action items to issue competitive market solicitations for unbundled REC products over the next two to four years.

The 2013 IRP Preferred Portfolio

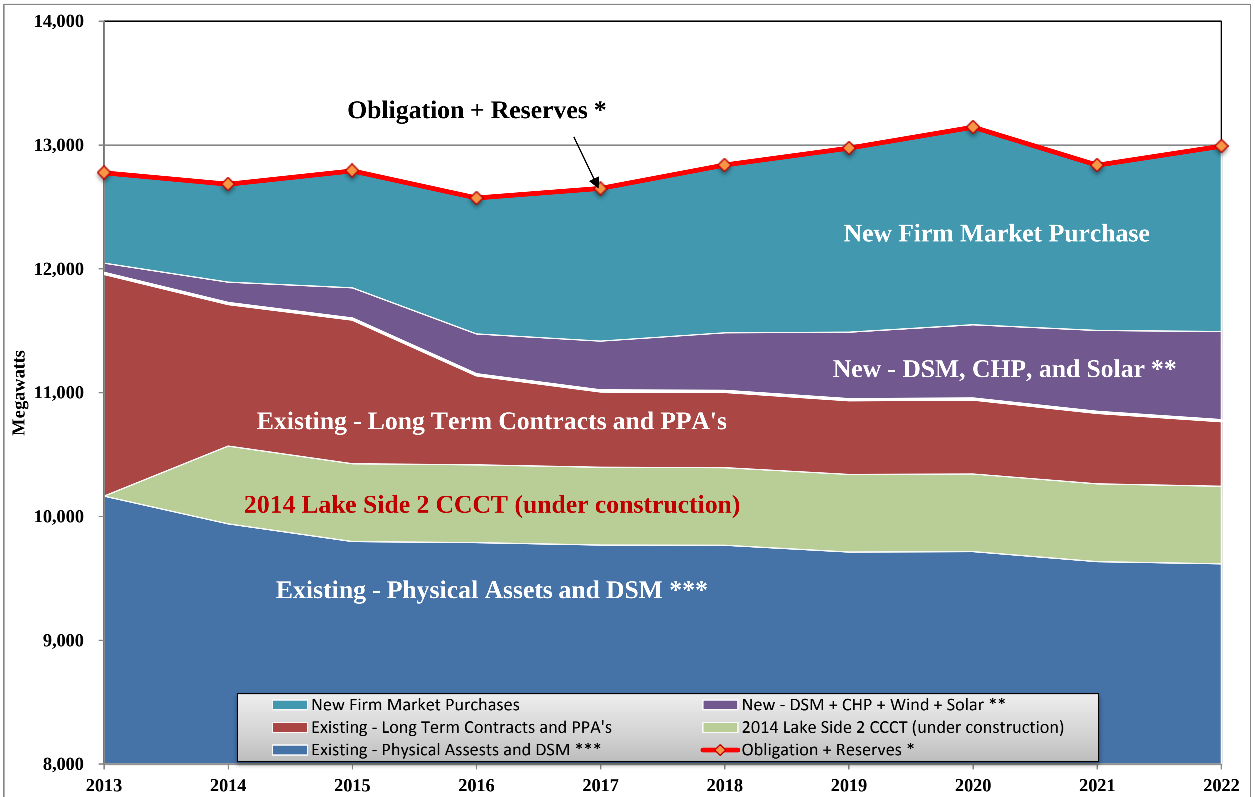
Table ES.3 lists the resource types and annual nameplate megawatt capacity additions over the period 2013 through 2032. Figure ES.4 shows how the preferred portfolio, along with existing resources, meets capacity requirements at the time of system peak through 2022. The drop in obligation and reserves in 2016 and 2021 coincides with termination of two exchange contracts. With reduced loads and favorable market conditions, incremental resource needs in the front 10 years of the planning horizon are met largely with cost-effective energy efficiency acquisitions and firm market purchases.

As informed by portfolio modeling completed for the 2013 IRP, the Company's action plan focuses on accelerating acquisition of cost effective DSM measures, to take advantage of the risk mitigation benefits of DSM resources by reducing the need for new firm market purchases in the near-term. With policy and market drivers contributing to unfavorable economics for new renewable resources, renewable resource additions in the 2013 IRP preferred portfolio reflect a near-term unbundled REC compliance strategy. Near-term renewable resources include small scale utility solar resources needed to meet Oregon requirements and distributed solar resources associated with the Utah Solar Incentive Program. Over the long-term, the 2013 IRP preferred portfolio includes additional wind resources, totaling 650 megawatts in the 2024 to 2025 timeframe, which contribute to meeting long-term state and assumed RPS obligations.

Table ES.3 – 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Expansion Options																					
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	**2,054**	**1,606**	**1,509**	**1,640**	**1,648**	**1,639**	**1,685**	**1,281**	**1,500**	

Figure ES.6 – Addressing PacifiCorp's Peak Capacity Deficit, 2013 through 2022

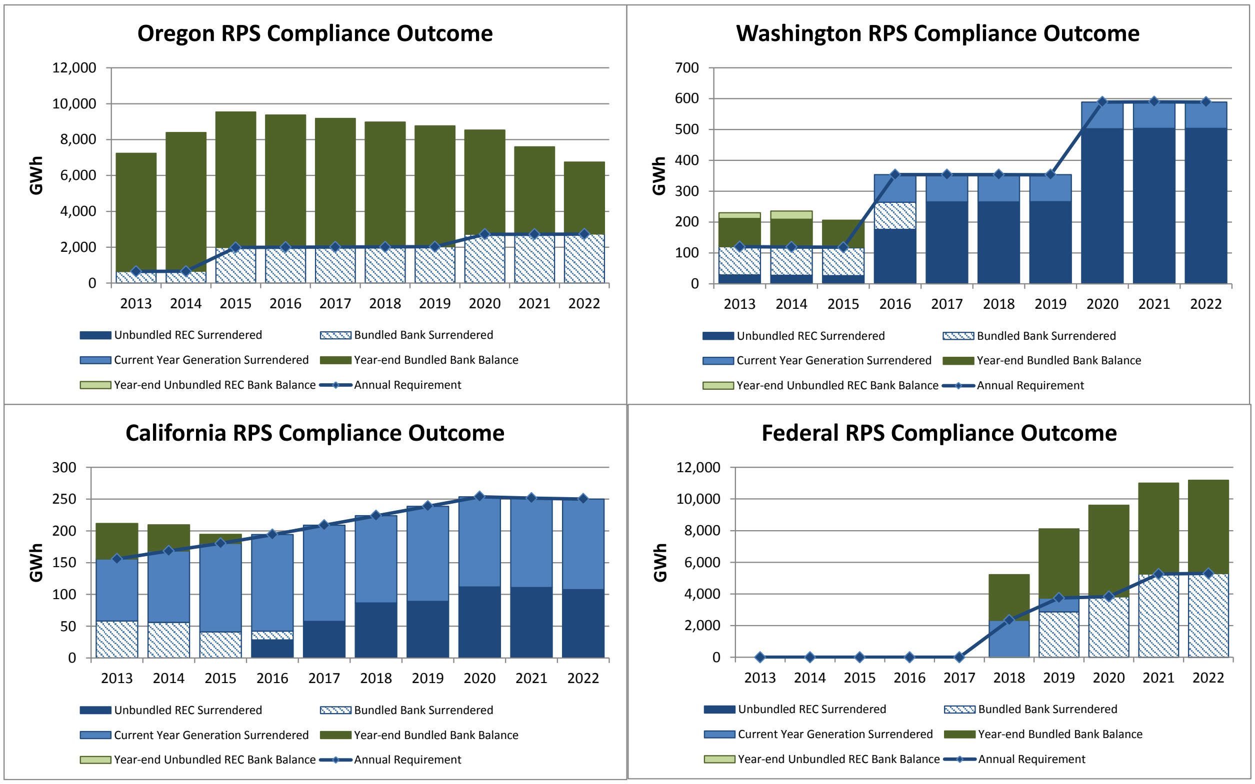


* Includes 13% Planning Reserves, Sales and Non-Owned Reserves
** Solar resources peak contribution is 8 MW by 2022 and Combined Heat and Power (CHP) contributes 12 MW.
*** Includes retirements, turbine upgrades, and gas repower. DSM includes both Class 1 and 2.

Figure ES.7 shows PacifiCorp's forecasted RPS compliance position for the California, Oregon, and Washington[4] programs, along with a federal RPS program scenario[5], covering the period 2013 through 2022 based on the preferred portfolio. Utah's RPS goal is tied to a 2025 compliance date, so the 2013 to 2022 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking and/or tradable RECs where allowed, to meet RPS requirements.

[4] The Washington RPS requirement is tied to January 1st of the compliance year.
[5] The assumed federal RPS requirements are applied to retail sales, with a target of 4.5 percent beginning in 2018, 7.1 percent in 2019-2020, 9.8 percent in 2021-2022, 12.4 percent in 2023-2024, and 20 percent in 2025

Figure ES.7 – Annual State and Federal RPS Position Forecasts



The 2013 IRP Action Plan

The 2013 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2013 IRP process. Table ES.4 details specific 2013 IRP action items by category.

Table ES.4 – 2013 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a.	**<u>Wind Integration</u>** • Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.
1b.	**<u>Renewable Portfolio Standard Compliance</u>** • With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations. – Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.
1c.	**<u>Renewable Energy Credit Optimization</u>** • On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.

1d.	**<u>Solar</u>** • Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the fourth quarter of 2013. • Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.
1e.	**<u>Capacity Contribution</u>** • Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.
Action Item	**2. Distributed Generation Actions**
2a.	**<u>Distributed Solar</u>** • Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.
2b.	**<u>Combined Heat & Power (CHP)</u>** • Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act PURPA Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp's system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.
Action Item	**3. Firm Market Purchase Actions**
3a.	**<u>Front Office Transactions</u>** • Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. – Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations.

	– Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.
Action Item	**4. Flexible Resource Actions**
4a.	**<u>Energy Imbalance Market (EIM)</u>** • Continue to pursue the EIM activities with the California Independent System Operator and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.
Action Item	**5. Hedging Actions**
5a.	**<u>Natural Gas Request for Proposal</u>** • Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company's process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.
Action Item	**6. Plant Efficiency Improvement Actions**
6a.	**<u>Plant Efficiency Improvements</u>** • Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. – By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. – Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures. – Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company's recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.
Action Item	**7. Demand Side Management (DSM) Actions**
7a.	**<u>Class 2 DSM</u>** • Acquire 1,425 – 1,876 GWh of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017. – Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact

evaluation, assess further expansion of the program.

- Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon.
  - Utah base case schedule is 1^{st} quarter 2014 with an accelerated target of 3^{rd} quarter 2013.
  - Washington base case schedule is 4^{th} quarter 2014, with an accelerated target of 1^{st} quarter 2014.
  - Wyoming, California, and Idaho base case schedule is 4^{th} quarter 2014, with an accelerated target of 2^{nd} quarter 2014.
- Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio.
- Increase acquisitions from business customers through prescriptive measures by expanding the "Trade Ally Network".
  - Base case target in all states is 3^{rd} quarter 2014, with an accelerated target of 4^{th} quarter 2013
- Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1^{st} quarter 2014.
- Increase the reach and effectiveness of "express" or "typical" measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units.
  - Utah base case schedule is 1^{st} quarter 2014 with an accelerated target of 3^{rd} quarter 2013.
  - Washington base case schedule is 4^{th} quarter 2014, with an accelerated target of 1^{st} quarter 2014.
  - Wyoming, California, and Idaho base case schedule is 4^{th} quarter 2014, with an accelerated target of 2^{nd} quarter 2014.
- Increase the reach of behavioral DSM programs:
  - Evaluate and expand the residential behavioral pilot.
    - Utah base case schedule is 2^{nd} quarter 2014, with an accelerated target of 4^{th} quarter 2013.
  - Accelerate commercial behavioral pilot to the end of the first quarter 2014.
  - Expand residential programs system-wide pending evaluation results.
    - System-wide target is 3^{rd} quarter 2015, with an accelerated target of 3^{rd} quarter 2014.
- Increase acquisition of residential DSM resources:
  - Implement cost effective direct install options by the end of 2013.
  - Expand offering of "bundled" measure incentives by the end of 2013.
  - Increase qualifying measures by the end of 2013.
  - Review and realign incentives.
    - Utah schedule is 1^{st} quarter 2014

	♦ Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014. ♦ Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014 – Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013. – By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required. – Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. – Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.
7b.	**Class 3 DSM** • Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 IRP.
Action Item	**8. Coal Resource Actions**
8a.	**Naughton Unit 3** • Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division. • Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process. • Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.
8b.	**Hunter Unit 1** • Complete installation of the baghouse conversion and low NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014.
8c.	**Jim Bridger Units 3 and 4** • Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.

8d.	**<u>Cholla Unit 4</u>** • Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.
Action Item	**9. Transmission Actions**
9a.	**<u>System Operational and Reliability Benefits Tool (SBT)</u>** • 60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). – For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment. – In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.
9b.	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. – Segment H Cascade Crossing, complete benefits analysis in 2013. – Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.
9c.	**<u>Sigurd to Red Butte 345 kilovolt Transmission Line</u>** • Complete project construction per plan.
Action Item	**10. Planning Reserve Margin Actions**
10a.	**<u>Planning Reserve Margin</u>** • Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve

	margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.
Action Item	**11. Planning and Modeling Process Improvement Actions**
11a.	**<u>Modeling and Process</u>** • Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process improvements in the 2015 IRP.
11b.	**<u>Cost/Benefit Analysis of DSM Resource Alternatives</u>** • Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.

CHAPTER 2 – INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP, the 12th plan submitted, fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public process with involvement from regulatory staff, advocacy groups, and other interested parties. As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are ultimately made by PacifiCorp in light of its obligations to its customers, regulators, and shareholders.

This IRP also builds on PacifiCorp's prior resource planning efforts and reflects continued advancements in portfolio modeling and analytical methods. These advancements include:

- Implementation of the Enterprise Production Model (EPM) interface, combining the functionality of System Optimizer and Planning and Risk components into a single model;
- Integration of Energy Gateway transmission investments into the portfolio modeling process;
- Introduction of the System Operational and Reliability Benefits Tool (SBT) to complement IRP modeling for a more complete picture of transmission costs and benefits of each IRP scenario;
- Enhancements to new resource modeling in System Optimizer resulting in improvement to resource selection, including modeling of environmental investments required to achieve compliance with known and prospection environmental regulations at existing coal resources, and increased granularity in the definition of bundle price breakpoints for energy efficiency measures;
- Addition of core case resource portfolios that assume accelerated acquisition of energy efficiency resources; and
- Use of the Renewable Portfolio Standard Scenario Maker, a new Excel spreadsheet tool for developing RPS-compliant renewable resource schedules.

Significant studies conducted to support the IRP include:

- An update of the 2010 demand-side management (DSM) and dispersed generation potentials study;
- An update of the 2011 loss of load study for determining an adequate capacity planning reserve margin for load and resource balance development;
- A state-of-the-art wind integration study;
- Market reliance scenario analysis; and
- Evaluation of price hedging strategies.

Finally, this IRP reflects continued alignment efforts with the Company's annual ten-year business planning process. The purpose of the alignment, initiated in 2008, is to:

- Provide corporate benefits in the form of consistent planning assumptions;
- Ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns that are the province of capital budgeting; and
- Improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

The planning alignment strategy also follows the 2008 adoption of the IRP portfolio modeling and analysis approach for requests for proposals (RFP) bid evaluation. This latter initiative was part of PacifiCorp's effort to unify planning and procurement under the same analytical framework. The Company used this analytical framework for bid evaluation in support of the all-source RFP reactivated in December 2009.

This chapter outlines the components of the 2013 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2013 Integrated Resource Plan Components

The basic components of PacifiCorp's 2013 IRP, and where they are addressed in this report, are outlined below.

- The set of IRP principles and objectives that the Company adopted for this IRP effort (this chapter).
- An assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- A description of PacifiCorp's transmission planning efforts and description of IRP modeling studies conducted to support Energy Gateway transmission financial evaluation (Chapter 4).
- A resource needs assessment covering the Company's load forecast, status of existing resources, and determination of the load and energy positions for the 10-year resource acquisition period (Chapter 5).
- A profile of the resource options considered for addressing future capacity and energy deficits (Chapter 6).
- A description of the IRP modeling, risk analysis, and portfolio performance assessment processes (Chapter 7).
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio (Chapter 8).
- An IRP action plan linking the Company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource risks (Chapter 9).

The IRP appendices, included as a separate volume, comprised of a detailed load forecast report (Appendix A), fulfillment of IRP regulatory compliance requirements, (Appendix B), the public input process (Appendix C), energy efficiency modeling (Appendix D), conservation voltage reduction and voltage optimization projects update (Appendix E), flexible resource needs assessment (Appendix F), historical plant water consumption data (Appendix G), 2012 wind integration cost study (Appendix H), 2012 stochastic loss of load study (Appendix I), an assessment of resource adequacy for western power markets, including a market reliance "stress" scenario analysis (Appendix J), detailed capacity expansion tables (Appendix K), stochastic simulation results (Appendix L), case study fact sheets (Appendix M), DSM decrement studies (Appendix N), and wind, and solar peak contributions (Appendix O).

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[6] The main role of the IRP is to serve as a roadmap for determining and implementing the Company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, risk, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting RFP bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

While PacifiCorp continues to plan on a system-wide basis, the Company recognizes that new state resource acquisition mandates and policies add complexity to the planning process and present challenges to conducting resource planning on this basis.

Public Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public process allowing stakeholder involvement in all phases of plan development. The Company held 26 public meetings/conference calls during 2012 and early 2013 designed to facilitate information sharing, collaboration, and expectations setting for the IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public meetings/conferences and major agenda items covered.

[6] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

Table 2.1 – 2013 IRP Public Meetings

Meeting Type	Date	Main Agenda Items
General Meeting	5/7/2012	2013 IRP kickoff meeting
General Meeting	6/20/2012	Demand-side management; portfolio development; wind integration
State Meeting	7/11/2012	Idaho state stakeholder comments
State Meeting	7/12/2012	Wyoming state stakeholder comments
General Meeting	7/13/2012	Portfolio case development; transmission scenarios and benefit analysis
State Meeting	7/19/2012	Oregon state stakeholder comments
State Meeting	7/20/2012	Washington state stakeholder comments
General Meeting	8/2/2012	Conservation voltage reduction; resource adequacy workshop; portfolio case development
General Meeting	8/13/2012	Supply-side resources; renewable portfolio standards; wind integration study
State Meeting	8/14/2012	Utah state stakeholder comments
General Conference Call	8/24/2012	Distributed generation resource assumptions
General Meeting	9/14/2012	Environmental compliance; load forecast; capacity load and resource balance; portfolio case development
General Conference Call	9/24/2012	Planning reserve margins; price curve scenarios and modeling methodology
General Conference Call	10/3/2012	Solar photovoltaic resources
General Meeting	10/24/2012	Utility-scale resource options; wind integration study; planning reserve margin
General Meeting	11/5/2012	Transmission benefit evaluation; stochastic modeling; preferred portfolio selection
General Meeting	11/27/2012	Planning reserve margin; methodology update overview
General Conference Call	12/6/2012	US Environmental Protection Agency and impacts on IRP modeling
General Conference Call	12/14/2012	Smart Grid
General Conference Call	12/18/2012	IRP filing schedule; core case fact sheet and price curve scenario updates
General Meeting	1/31/2013	Core case portfolio results; wind integration study
General Meeting	2/27/2013	Transmission system benefits tool; IRP modeling results update; class 2 DSM supply curves
General Meeting	3/21/2013	Modeling update; draft preferred portfolio
General Meeting	4/5/2013	Draft preferred portfolio; draft action plan
General Meeting (Confidential)	4/17/2013	2013 IRP Confidential Volume 3
General Meeting	4/17/2013	Draft IRP document; sensitivity analysis results

Appendix C provides more details concerning the public meeting process and individual meetings.

In addition to the public meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The Company maintains a public website (http://www.pacificorp.com/es/irp.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support stakeholder communications and address inquiries by public participants. In response to stakeholder requests, PacifiCorp has also introduced an additional IRP comments website intended for PacifiCorp's IRP public participants only (http://www.pacificorp.com/es/irp/irpcomments.html)

CHAPTER 3 – THE PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Significantly lower wholesale power prices and natural gas prices in the 2013 IRP than market prices in the 2011 IRP, caused mainly by a decline in forward natural gas prices as a result of the continued growth in prolific shale gas plays in North America and reduced regional loads. Loss of momentum in federal efforts to develop comprehensive federal energy and climate change compliance requirements, leading to continued uncertainty regarding the long-term investment climate for clean energy technologies.
- The U.S. Environmental Protection Agency (EPA) has promulgated new source performance standards to regulate greenhouse gas emissions from new sources, it has not established a schedule to promulgate rules applicable to existing sources. Nevertheless, public and legislative support for clean energy policies at the state level remains robust.
- Aggressive efforts by the EPA to regulate electric utility plant emissions, including greenhouse gases, criteria pollutants and other emissions.
- Near-term procurement activities related to natural gas supply and transportation and Oregon solar resources.

Introduction

This chapter profiles the major external influences that impact PacifiCorp's long-term resource planning as well as recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Sluggish economic growth continues to influence load growth expectations throughout the 2013 IRP planning cycle. In light of current economic conditions, the Company continues to evaluate capital projects for least cost adjusted for risk resources based on known and measurable compliance requirements.

Concerning the power industry marketplace, the major issues addressed include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). As discussed elsewhere in the IRP, future natural gas prices and the role of gas-fired generation and market purchases are some of the critical factors impacting the determination of the preferred portfolio that best balances low-cost and low-risk planning objectives.

On the government policy and regulatory front, a significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives, particularly at the state level. A high-level summary of the Company's greenhouse gas emissions mitigation strategy, as well as an overview of the Electric Power Research Institute's study on carbon dioxide price impacts on western power markets, follows. This chapter also reviews the significant policy developments for currently-regulated pollutants

Other topics covered in this chapter include regulatory updates on the Environmental Protection Agency, regional and state climate change regulation, the status of renewable portfolio standards, and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp's system does not operate in an isolated market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp participates in the wholesale market in this fashion, making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand. The market is not without its risks, as the experience of the 2000-2001 market crisis, followed by the rapid price escalation during the first half of 2008 and subsequent demand destruction and rapid price declines in the second half of 2008, have underscored. Unanticipated paradigm shifts in the market place can also cause significant changes in market prices as evidenced by advancements in the ability of natural gas producers to cost-effectively access abundant shale gas supplies over the past several years.

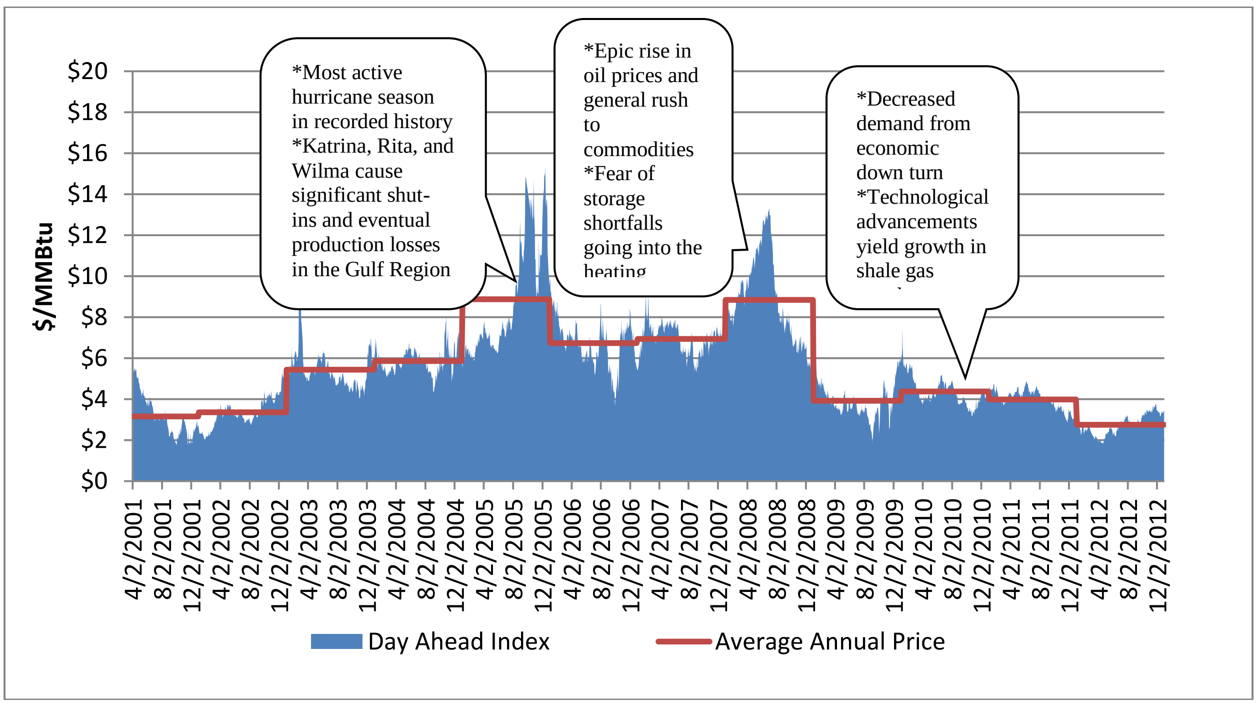
As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, WECC publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. A review of the WECC power supply assessments is provided in Appendix J. The latest assessment, published in October 2012, indicates that with the exception of Northern and Southern California, US WECC has adequate resources through 2022. If only existing units and those under construction are considered, then Northern and Southern California will need capacity in 2015 and 2017, respectively.

There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices have become a critical determinant in establishing western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on this IRP, as in past IRPs, is the prospect of future greenhouse gas policy. A broad landscape of federal, regional, and state proposals aiming to curb greenhouse gas emissions continues to widen the range of plausible future energy costs, and consequently, future electricity prices. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

Natural Gas Uncertainty

Over the last twelve years, North American natural gas markets have demonstrated exceptional price volatility. Figure 3.1 shows historical day-ahead prices at the Henry Hub benchmark from April 2, 2001 through December 28, 2012. Over this period, day-ahead gas prices settled at a low of $1.72 per million British thermal units (MMBtu) on November 16, 2001 and at a high of $18.41 per MMBtu on February 25, 2003. During the fall and early winter of 2005, prices breached $15 per MMBtu after a wave of hurricanes devastated the gulf region in what turned out to be the most active hurricane season in recorded history. Prices later topped $13 per MMBtu in the summer of 2008 when oil prices began their epic climb above $140 per barrel in the months preceding the global credit crisis. By early 2009 slow economic growth coupled with abundant shale gas supplies pressured natural gas prices to dip below $5 per MMBtu; day-ahead prices averaged $3.92 per MMBtu for 2009. Prices rose modestly and then ticked down with day-ahead natural gas prices averaging $4.37, $3.99, and $2.75 per MMBtu for 2010 through 2012, respectively. Today's natural gas prices are not adequate to incent new drilling; the continued supply of natural gas is a result of improvements in well productivity, production from wells being "held by production", and large amounts of price insensitive dry gas produced as a byproduct in wet gas and shale oil plays.

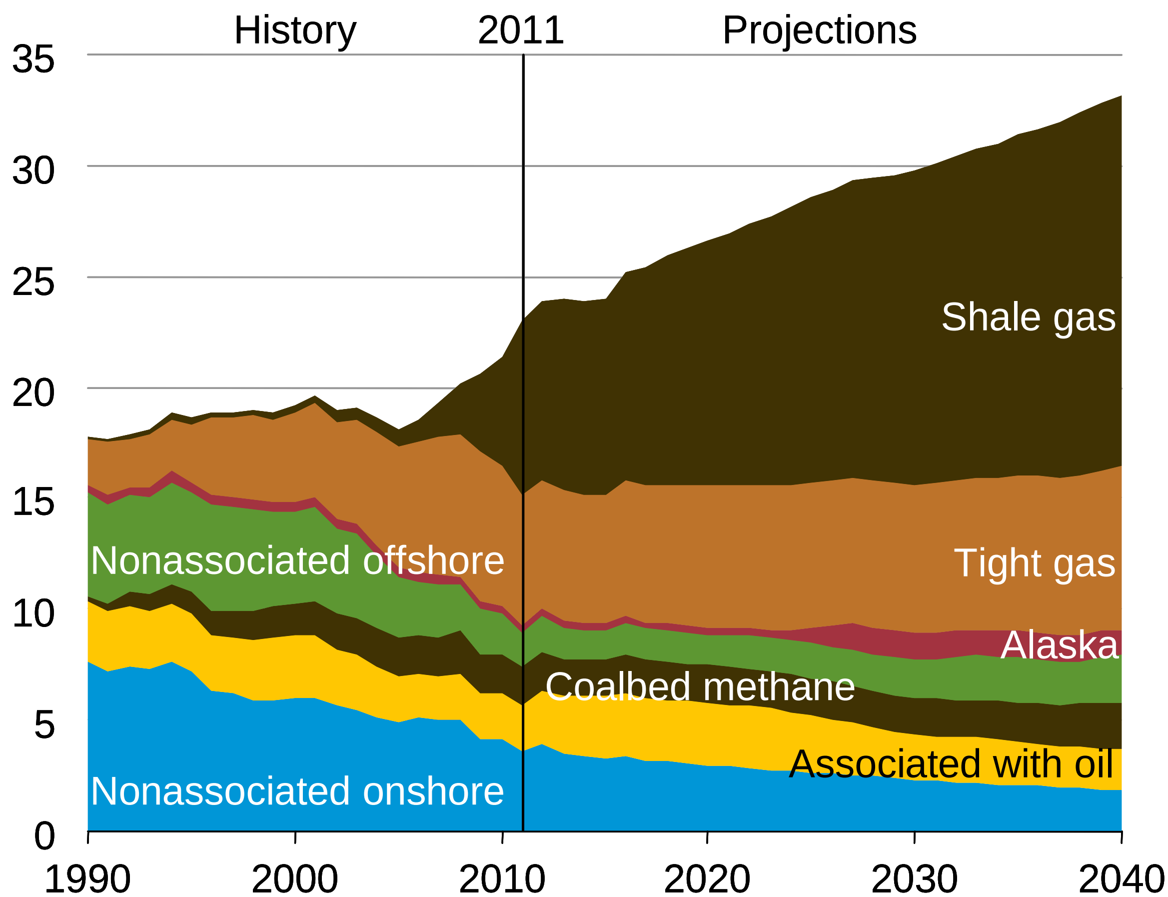
Figure 3.1 – Henry Hub Day-ahead Natural Gas Price History



Source: Intercontinental Exchange (ICE), Over the Counter Day-ahead Index

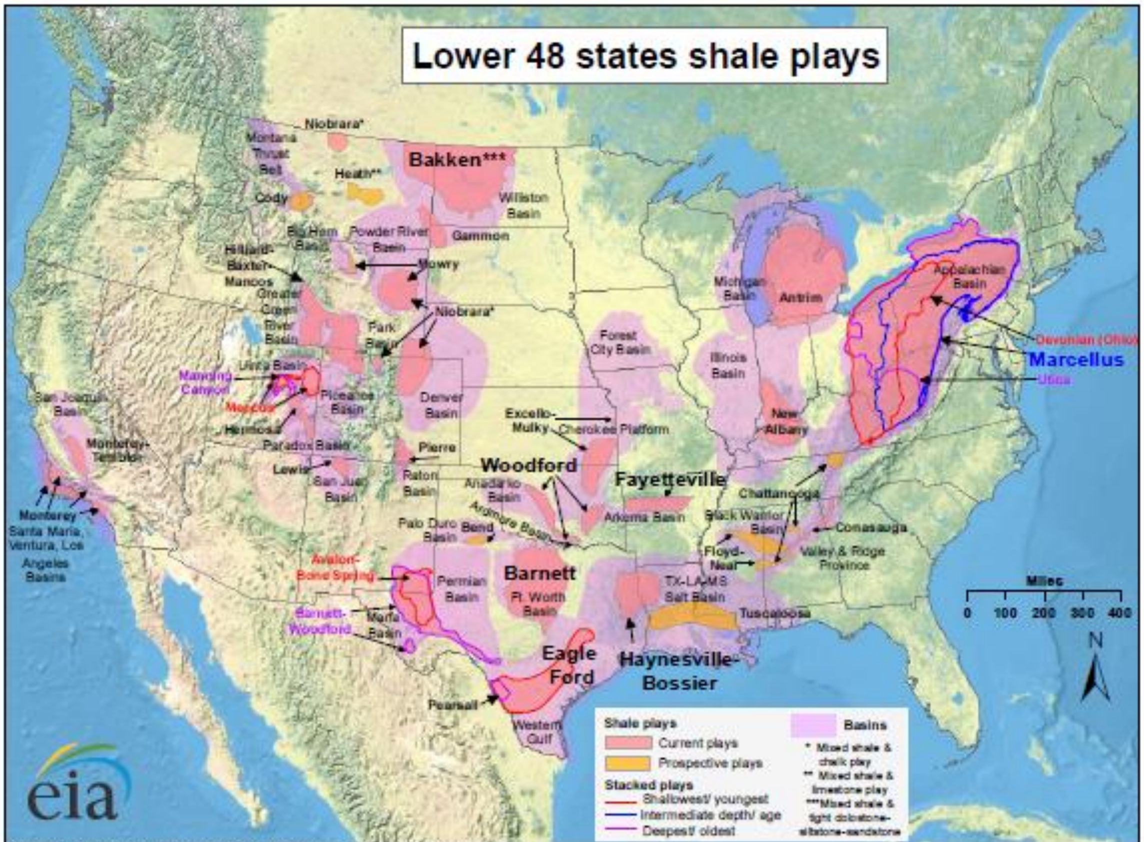
Beyond the geopolitical, extreme weather, and economic events that spawned day-ahead prices above $13 per MMBtu, as recently as summer 2008, natural gas prices have exhibited an upward trend from approximately $3 per MMBtu in 2002 to nearly $9 per MMBtu in 2008 followed by a downward trend starting 2009. Over much of the former period, declining volumes from conventional, mature producing regions largely offset growth from unconventional resources. However, prices in 2009 through 2012 reflect reduced demand and significant production gains from unconventional domestic supplies such as tight and shale gas. Figure 3.2 shows a breakdown of U.S. supply; Figure 3.3 illustrates the shale plays in the lower 48 states.

Figure 3.2 - U.S. Dry Natural Gas Production (TCF) by Source



Source: U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2013, Early Release, December 5, 2012.

Figure 3.3 – Shale Plays in Lower 48 States



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Source: U.S. Department of Energy, Energy Information Administration

The supply/demand balance began to shift in 2007 and 2008 thanks to an unprecedented and unexpected burst of growth from unconventional domestic supplies across the lower 48 states. With rapid advancements in horizontal drilling and hydraulic fracturing technologies, producers began drilling in geologic formations such as shale. Some of the most prominent contributors to the rapid growth in unconventional natural gas production have been the Barnett Shale located beneath the city of Fort Worth, Texas, the Woodford Shale located in Oklahoma and the Marcellus Shale located in Pennsylvania. Strong growth also continued in the Rocky Mountain region.

Prior to 2009, forecasters expected that a gradual restoration of improved supply/demand balance would be achieved largely with growth in liquefied natural gas (LNG) imports. Indeed, there has been tremendous growth in global liquefaction facilities located in major producing regions. This expectation led to significant investments in regasification capacity to accommodate the need for future LNG imports. However, the evolution of unconventional supplies and continually growing estimates of shale gas reserves has significantly changed the need for LNG imports. Today, liquefaction, not regasification, facilities are being proposed with one having already been approved. As such, the U.S. is anticipated to export 0.6 billion cubic feet per day (BCF/D) by 2016 reaching 4.5 BCF/D by 2027. Several factors contribute to a wide range of price uncertainty in the mid- to long-term. Supporting downside price risk, technological advancements underlying the recent expansion of unconventional supplies opens the door to tremendous growth potential in both production and proven reserves from shale formations across North America. Increasing well productivity, technological innovations, and large volumes of price insensitive associated gas have flattened the supply curve. In the long-term, moderated oil prices from large oil shale finds could dampen demand for LNG exports and for oil-to-gas substitution in the transportation sector. Supporting upside price risk, the next generation of unconventional supplies may prove to be more difficult or costly to extract with the possibility of drilling restrictions due to environmental concerns associated with hydraulic fracturing, which would raise marginal costs, and consequently, raise prices. In addition, high oil prices could incent increased LNG exports and increased oil-to-gas substitution in the transportation sectors.

Western regional natural gas markets are likely to remain well-connected to overall North American natural gas prices. Rocky Mountain region production has caused prices at the Opal hubs to transact at a discount to the Henry Hub benchmark in recent years. Major pipeline expansions to the mid-west and east coupled with further pipeline expansion plans to the west have provided price support for Opal; however, prices remain discounted to Henry Hub. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to other hubs in the region. This has been driven in large part by declines in Canadian natural gas production and reduced imports into the U.S. In the near-term, Canadian imports from British Columbia are expected to remain below historical levels lending support for basis differentials in the region; however, in the mid- to long-term, production potential from regional shale formations will have the opportunity to soften the Sumas basis.

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces a continuously-changing environment with regard to electricity plant emission regulations. Although the exact nature of these changes remains uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in PacifiCorp's generation portfolio. PacifiCorp monitors these regulations to determine the potential impact on the company's generating assets and participates in the rulemaking process by filing comments on various proposals and participating in scheduled hearings to provide the company's assessment on such proposals.

Timing of Environmental Protection Agency (EPA) Regulation

The U.S. EPA has undertaken a multi-pronged approach to minimize air, land, and water-based environmental impacts. Many environmental regulations from the EPA are in various parallel stages of development. Even in cases where the EPA has established deadlines for proposal or finalization of a rule, these deadlines are frequently extended, making it difficult to determine not only the final outcome of a rule, but when it may ultimately impact the Company.

Aside from potential greenhouse gas regulations, few of the environmental regulations under consideration are likely to materially impact the industry in isolation; in aggregate, however, they are expected to have a significant impact – especially on the coal-fueled generating units that supply approximately 42 percent of the nation's electricity. As such, each of these regulations will have a significant impact on the utility industry and could affect environmental control requirements, limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp's coal-fueled generation assets.

Federal Climate Change Legislation

PacifiCorp continues to evaluate the potential impact of climate change legislation at the federal level. The impact of a given legislative proposal varies significantly depending on its selection of key design criteria (i.e., level of emissions cap, rate of decline of the cap, the use of carbon offsets, allowance allocation methodology, the use of safety valves, and etc.) and macro-economic assumptions (i.e., electricity load growth, fuel prices – especially natural gas, commodity prices, new technologies, etc.).

To date, no federal legislative climate change proposal has successfully been passed by both the U.S. House of Representatives and the U.S. Senate for consideration by the President. The two most prominent legislative proposals introduced for attempted passage through Congress have been the Waxman-Markey bill in 2009 and the Kerry-Lieberman bill in 2010; neither measure was able to accumulate enough support to pass.

In the 112th Congress, several bills were introduced designed to limit, remove, or suspend EPA's asserted regulatory authority over greenhouse gases, none of which were successful. In the President's State of the Union Address, the 113th Congress was challenged by the President to pursue a bipartisan, market-based solution to climate change, indicating if Congress did not act soon, the President would direct his Cabinet to implement executive action to reduce greenhouse gas emissions. On February 14, 2013, Senators Bernie Sanders and Barbara Boxer introduced climate legislation, the Climate Protection Act of 2013, which would, among other things, impose a carbon fee of 20 dollars per ton on coal, petroleum and natural gas producers beginning in 2014.

EPA Regulatory Update – Greenhouse Gas Emissions

In conjunction with its greenhouse gas endangerment finding in 2009, the EPA has aggressively pursued the regulation of greenhouse gas (GHG) emissions. Key recent initiatives include the following:

New Source Review / Prevention of Significant Deterioration (NSR / PSD)

On May 13, 2010, the EPA issued a final rule that addresses GHG emissions from stationary sources under the Clean Air Act (CAA) permitting programs, known as the "tailoring" rule. This final rule sets thresholds for GHG emissions that define when permits under the New Source Review (NSR) / Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs are required for new and existing industrial facilities. This final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The rule also establishes a schedule that will initially focus CAA permitting programs on the largest sources with the most CAA permitting experience. Finally, the rule expands to cover the largest sources of GHGs that may not have been previously covered by the CAA for other pollutants.

Guidance for Best Available Control Technology (BACT)

On November 10, 2010, the EPA published a set of guidance documents for the tailoring rule to assist state permitting authorities and industry permitting applicants with the Clean Air Act PSD and Title V permitting for sources of GHGs. Among these publications was a general guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases," which included a set of appendices with illustrative examples of Best Available Control Technology (BACT) determinations for different types of facilities, which are a requirement for PSD permitting. The EPA also provided white papers with technical information concerning available and emerging GHG emission control technologies and practices, without explicitly defining BACT for a particular sector. In addition, the EPA has created a "Greenhouse Gas Emission Strategies Database," which contains information on strategies and control technologies for GHG mitigation for two industrial sectors: electricity generation and cement production.

The guidance does not identify what constitutes BACT for specific types of facilities, and does not establish absolute limits on a permitting authority's discretion when issuing a BACT determination for GHGs. Instead, the guidance emphasizes that the five-step top-down BACT process for criteria pollutants under the CAA generally remains the same for GHGs. While the guidance does not prescribe BACT in any area, it does state that GHG reduction options that improve energy efficiency will be BACT in many or most instances because they cost less than other environmental controls (and may even reduce costs) and because other add-on controls for GHGs are limited in number and are at differing stages of development or commercial availability. Utilities have remained very concerned about the NSR implications associated with the tailoring rule (the requirement to conduct BACT analysis for GHG emissions) because of great uncertainty as to what constitutes a triggering event and what constitutes BACT for GHG emissions.

New Source Performance Standards (NSPS) for Greenhouse Gases

On December 23, 2010, in a settlement reached with several states and environmental groups in New York v. EPA, the EPA agreed to promulgate emissions standards covering GHGs from both new and existing electric generating units under Section 111 of the CAA by July 26, 2011 and issue final regulations by May 26, 2012.[7] NSPS are established under the CAA for certain industrial sources of emissions determined to endanger public health and welfare and must be reviewed every eight years. While NSPS were intended to focus on new and modified sources and effectively establish the floor for determining what constitutes BACT, the emission guidelines will apply to existing sources as well. In April 2012, the EPA proposed a NSPS for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per megawatt hour (MWh). The proposal exempted simple cycle combustion turbines from meeting the standards. The public comment period closed in June 2012 and a final rule is expected by April 2013. While the EPA is also under a consent decree obligation to establish GHG NSPS for modified and existing sources, EPA has indicated it has not established a schedule for doing so.

[7] The deadlines for EPA to take proposed and final actions have since been extended. EPA also entered into a similar settlement the same day to address greenhouse gas emissions from refineries with proposed regulations by December 15, 2011 and final regulations by November 15, 2012.

The emissions guidelines issued by the EPA will be used by states to develop plans for reducing emissions and include targets based on demonstrated controls, emission reductions, costs and expected timeframes for installation and compliance, and may be less stringent than the requirements imposed on new sources. States must submit their plans to the EPA within nine months after the guidelines' publication unless the EPA establishes a different schedule. States have the ability to apply less stringent standards or longer compliance schedules if they demonstrate that following the federal guidelines is unreasonably cost-prohibitive, physically impossible, or that there are other factors that reasonably preclude meeting the guidelines. States may also impose more stringent standards or shorter compliance schedules.

EPA Regulatory Update – Non-Greenhouse Gas Emissions

Several categories of EPA regulations for non-GHG emissions are discussed below:

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

Currently, PacifiCorp's generation units must comply with the federal CAA, which is implemented by the States subject to EPA approval and oversight. The CAA requires the EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants considered harmful to public health and the environment. For a given NAAQS, the EPA and/or a state identifies various control measures that once implemented are meant to achieve an air quality standard for a certain pollutant, with each standard rigorously vetted by the scientific community, industry, public interest groups, and the general public.

Particulate matter (PM), sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead are often grouped together because under the CAA, each of these categories is linked to one or more National Ambient Air Quality Standards (NAAQS). These "criteria pollutants", while undesirable, are not toxic in typical concentrations in the ambient air. Under the CAA, they are regulated differently from other types of emissions, such as hazardous air pollutants and greenhouse gases.

Within the past few years, the EPA established new standards for particulate matter, sulfur dioxide, and nitrogen dioxide. While the EPA had proposed to implement new ozone standards in 2011, it was determined that the standards should be deferred until the next regularly scheduled review in 2013.

Clean Air Transport Rule

In July 2009, EPA proposed its Clean Air Transport Rule (Transport Rule), which would require new reductions in SO_2 and nitrogen oxide (NO_X) emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. The Transport Rule was intended to help states attain NAAQS set in 1997 for ozone and fine particulate matter emissions. The rule replaced the Bush administration's Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS. While the rule was finalized as the Cross-State Air Pollution Rule (CSAPR) in July 2011, litigation in the D.C. Circuit Court of Appeals resulted in a stay on the implementation of the CSAPR in December 2011; Ultimately, in August 2012, the

D.C. Circuit Court of Appeals vacated the CSAPR in a 2-1 decision after it determined the rule exceeded the EPA's statutory authority. The EPA sought a full review of the CSAPR ruling by the entire D.C. Circuit; however, in January 2013, the court denied the request. Until a replacement rule is adopted and implemented, the CAIR remains in place.

PacifiCorp does not own generating units in states identified by the CAIR or CSAPR and thus will not be directly impacted; however, the Company intends to monitor amendments to these rules closely in the event that the scope of a replacement rule extends the geographic scope of impacted states.

Regional Haze

EPA's rule to address Regional Haze visibility concerns will drive additional NO_x reductions particularly from facilities operating in the Western United States, including the states of Utah and Wyoming where PacifiCorp operates generating units and Arizona, where PacifiCorp owns a generating unit subject to the Regional Haze Rule. Unlike CAIR or CSAPR, which have no direct impact on PacifiCorp's states with generation, the finalized Regional Haze regulatory activity will have an impact.

On June 15, 2005, EPA issued final amendments to its July 1999 Regional Haze rule. These amendments apply to the provisions of the Regional Haze rule that require emission controls known as Best Available Retrofit Technology (BART), for industrial facilities meeting certain regulatory criteria that with emissions that have the potential to impact visibility. These pollutants include $PM_{2.5}$, NO_X, SO_2, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART as well as establishing BART emissions limits for those facilities.

The state of Utah issued a regional haze state implementation plan (SIP) requiring the installation of SO_2, NO_x and particulate matter (PM) controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah Regional Haze SIP and disapproved the NO_x and PM portions. Certain groups have appealed the EPA's approval of the SO_2 SIP. The date for appealing the disapproval of the NO_x and PM portions of the SIP is March 25, 2013. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality is undertaking an additional BART analysis for each of Hunter Units 1 and 2 and Huntington Units 1 and 2, which will be provided to the EPA as a supplement to the existing Utah SIP. It is unknown whether and how the Utah Division of Air Quality's supplemental analysis will impact the EPA's approval and disapproval of the existing SIP.

In Wyoming, the state issued two regional haze SIPs requiring the installation of SO_2, NO_x and PM controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the SO_2 SIP in December 2012, but initially proposed to disapprove portions of the NO_x and PM SIP and instead issue a federal implementation plan (FIP). The EPA proposed to approve the installation of selective catalytic reduction (SCR) equipment and a baghouse at Naughton Unit 3 by December 31, 2014; to approve the installation of SCR equipment at Jim Bridger Unit 3 by December 31, 2015; and to approve the installation of SCR equipment at Jim

Bridger Unit 4 by December 31, 2016. The EPA proposed to disapprove the NO_x and PM SIP for Jim Bridger Units 1 and 2 and instead accelerate the installation of SCR equipment to 2017 from 2021 and 2022, but agreed to accept comment on maintaining the original schedule as the state proposed. In addition, the EPA proposed to reject the SIP for the Wyodak facility and Dave Johnston Unit 3 and require the installation of selective non-catalytic reduction (SNCR) equipment within five years, as well as require the installation of low-NO_x burners and overfire air systems at Dave Johnston Units 1 and 2. Since the EPA's initial proposal, which was to have been final in October 2012 and was extended to December 2012, the EPA has withdrawn its proposed action on the SIP and its proposed FIP and has indicated its intent to re-propose action on the Wyoming NO_x and PM SIP by March 29, 2013, and take final action by September 27, 2013. In the meantime, certain groups have appealed the EPA's approval of the Wyoming SO_2 SIP which, consistent with the Utah SO_2 SIP, required emission reductions of SO_2 to be enforced through a three-state milestone and backstop trading program.

In Arizona, the state issued a Regional Haze SIP requiring, among other things, the installation of SO_2, NO_x and PM controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP for the disapproved portions. PacifiCorp filed an appeal in the Ninth Circuit Court of Appeals regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests.

Other cases are pending before the Tenth Circuit Court of Appeals with regard to similar appeals of FIPs issued by the EPA in New Mexico and Oklahoma.

Mercury and Hazardous Air Pollutants

In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to permanently limit and reduce mercury emissions from coal-fired power plants under a market-based cap-and-trade program. However, the CAMR was vacated in February 2008, with the court finding the mercury rules inconsistent with the stipulations of Section 112 of the CAA.

The vacated CAMR was replaced by EPA with the more extensive Mercury and Air Toxics Standards (MATS) with an effective date of April 16, 2012. The MATS rule requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. While the final MATS requirements continue to be reviewed by PacifiCorp, the Company believes its emission reduction projects completed to date or currently permitted or planned for installation, including the scrubbers, baghouses and electrostatic precipitators required under other EPA requirements, are consistent with achieving the MATS requirements and will support PacifiCorp's ability to comply with the final standards for acid gases and non-mercury metallic hazardous air pollutants. PacifiCorp will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities and otherwise comply with the standards.

PacifiCorp currently anticipates that retiring the Carbon plant in early 2015 will be least-cost alternative to comply with the MATS and other environmental regulations. PacifiCorp continues to assess other issues, such as potential transmission system impacts, that could impact its ultimate decision regarding the Carbon plant, including the timing of retirement and decommissioning.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants.

CCRs are currently considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA proposed in 2010 to regulate CCRs for the first time. EPA is considering two possible options for the management of CCRs. Both options fall under the RCRA. Under the first option, EPA would list these residual materials as special wastes subject to regulation under Subtitle C of RCRA with requirements from the point of generation to disposition including the closure of disposal units. Under the second option, EPA would regulate coal combustion residuals as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of coal combustion residuals. Under either option for regulation, surface impoundments utilized for coal combustion byproducts would have to be closed unless they could meet more stringent regulatory requirements. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts.

While the public comment period on EPA's proposal to regulate coal combustion byproducts closed in November 2010, the EPA has not indicated when the rule will be finalized, and the substance of the final rule is not known. In briefs filed in litigation pending in the D.C. Circuit Court of Appeals to force the EPA to meet a deadline to issue final coal combustion byproduct rules, the EPA indicated it needs until at least 2014 to review comments, formulate a risk assessment and coordinate the rule with the effluent limit guidelines discussed herein.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electricity generating facilities that take in more than 50 million gallons of water per day. These rules were aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Court of Appeal for the Second Circuit remanded almost all aspects of the rule to the EPA without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the U.S. Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding best technology available for minimizing adverse environmental impact at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The Supreme Court remanded the case back to the Second Circuit Court of Appeals to conduct further proceedings consistent with its opinion.

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirement for electric generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the U.S. and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S. Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. While the rule was required to be finalized by the EPA by July 2012, the deadline for finalizing the rule was extended to June 2013. Assuming the final rule is issued by June 2013, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2014.

Effluent Limit Guidelines

EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines) in 1974 with subsequent revisions in 1977 and 1982. The EPA is currently under a deadline of April 19, 2013 to propose revised effluent limit guidelines and sent the proposed rulemaking package to the Office of Management and Budget for interagency review in January 2013. The EPA is required, under the terms of a stipulated extension to a consent decree, to finalize the rule by May 2014. While the EPA has indicated that the growing use of flue-gas desulfurization systems has increased the amount of toxic metals discharged from power plants, until the required technology-based effluent limitations and standards are proposed and finalized, PacifiCorp cannot determine the potential impact of the rules on its facilities. In addition, the effluent limit guidelines will apply to gas-fired generation.

State Climate Change Regulation

While national greenhouse gas legislation has yet to be successfully adopted, state initiatives continue with the active development of climate change regulations that will impact PacifiCorp.

California

An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. In 2006, the California Legislature passed and Governor Schwarzenegger signed Assembly Bill 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law. It directed the California Air Resources Board to begin developing discrete early actions to reduce greenhouse gases while also preparing a scoping plan to identify how best to reach the 2020 limit.

Pursuant to the authority of the Global Warming Solutions Act, in October 2011, the California Air Resources Board adopted a greenhouse gas cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012 and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances, and purchase the required amount of allowances necessary to meet its compliance obligations.

Oregon and Washington

In 2007, the Oregon Legislature passed HB 3543 Global Warming Actions which establishes greenhouse gas reduction goals for the state that (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2009, the Legislature passed SB 101 which requires the Public Utility Commission of Oregon (OPUC) to report to the Legislature before November 1 of each even-numbered year on the estimated rate impacts for Oregon's regulated electric and natural gas companies associated with meeting the greenhouse gas reduction goals of 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2012.

During the 2013 session, the Oregon Legislature is considering a number of bills relating to the implementation of a carbon tax; it is unknown whether those bills will be passed. In addition, Oregon is considering the viability of establishing a voluntary greenhouse gas emission program that would allow utilities to consider alternative forms of regulation designed to lower greenhouse gas emissions.

In 2008, the Washington State Legislature approved the Climate Change Framework E2SHB 2815, which establishes state greenhouse gas emissions reduction limits. Washington's emission limits are to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050. In the 2013 session, the Washington Legislature is considering a bill that would develop recommendations to achieve the state's greenhouse gas emission limits.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted greenhouse gas emission performance standards applicable to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility. The standards are currently set at 1,100 pounds of carbon dioxide equivalent per MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based upon their global warming potential. The Washington Department of Commerce is pursuing a rulemaking process to lower the emissions performance standard; while the rulemaking is not yet final, the Department of Commerce most recently proposed an emission performance standard of 970 pounds of carbon dioxide per MWh. Efforts are also underway in Oregon to effectuate changes to the state's emission performance standard to broaden its applicability.

Renewable Portfolio Standards

A renewable portfolio standard (RPS) requires each retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facility, purchasing renewable energy from someone else's facility, using renewable energy credits (RECs) which certify renewable energy has been created, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their requirements with respect to timeframe, resource eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and whether they allow REC trading. By the end of 2012, twenty-nine states, the District of Columbia and two territories had adopted a mandatory RPS, eight states and two territories had adopted RPS goals.[8]

Within PacifiCorp's service territory, California, Oregon, and Washington have adopted a mandatory RPS and Utah has adopted an RPS goal. Each of these states' legislation and requirements are summarized in Table 3.1, with additional discussion below.

Table 3.1 – State RPS Requirements

	CA	OR	WA	UT
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011)	• Senate Bill 838, Oregon Renewable Energy Act (2007) • House Bill 3039 (2009)	• Initiative Measure No. 937 (2006)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by 2010 • Average of 20% through 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 and beyond • Based on the retail load for that compliance period	• At least 5% of load by December 31, 2014 • At least 15% by December 31, 2019 • At least 20% by December 31, 2024 • At least 25% by December 31, 2025 and thereafter • Based on the retail load for that year • Invest in 20 MW solar by January 1, 2020 -- PGE, PacifiCorp and Idaho Power combined	• At least 3% of load by January 1, 2012 • At least 9% by January 1, 2016 • At least 15% by January 1, 2020 • Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted retail sales for the calendar year 36 month prior to the target year • Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM

[8] Database of State Incentives for Renewables & Efficiency (DSIRE)

California

California originally established its RPS program with passage of Senate Bill 1078 in 2002. There have been several bills that have since been passed into law to amend the program. In the 2011 1st Extraordinary Special Session, the California Legislature passed Senate Bill 2[9] (SB 2 (1x)) to increase California's RPS to 33 percent by 2020. SB 2 (1x) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities, and established the following targets for renewable procurement based on retail load:

- Extends the current 2010 mandate of procuring 20 percent of electricity from renewable resources out to December 31, 2013;
- Requires 25 percent of electricity to come from renewable resources by December 31, 2016; and,
- Requires 33 percent of electricity to come from renewable resources by December 31, 2020, and each year thereafter.

Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. The RECs must be certified as eligible for the California RPS by the California Energy Commission and tracked in the Western Renewable Energy Generation Information System (WREGIS).

In addition to increasing the target from 20 percent in 2010 to 33 percent in 2020 and each year thereafter, SB 2 (1x) also created multi-year compliance periods. The California Public Utilities Commission approved the methodology for calculating the multi-year compliance periods and years thereafter; this is provided below in Table 3.2.

Table 3.2 – California Compliance Period Requirements

California RPS Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1: 2011-2013	20% * 2011 Retail Sales + 20% * 2012 Retail Sales + 20% * 2013 Retail Sales
Compliance Period 2: 2014-2016	21.7% * 2014 Retail Sales + 23.3% * 2015 Retail Sales + 25% * 2016 Retail Sales
Compliance Period 3: 2017-2020	27% * 2017 Retail Sales + 29% * 2018 Retail Sales + 31% * 2019 Retail Sales + 33% * 2020 Retail Sales
2021 and Beyond	33% * Annual Retail Sales

SB 2 (1x) also established new "portfolio content categories" for RPS procurement, which delineated the type of renewable product that may be used for compliance and also set minimum

[9] http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf

and maximum limits on certain procurement content categories that can be used for compliance. The portfolio content categories pursuant to SB 2 (1x) are described below:

Portfolio Content Category 1 includes energy and RECs that meet either of the following criteria (a) have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source. The use of another source to provide real-time ancillary services required to maintain an hourly or sub-hourly import schedule into a California balancing authority shall be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category; or (b) have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled[10] renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.

Additionally, the California Public Utilities Commission established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period.

Table 3.3 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1: 2011-2013	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2: 2014-2016	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3: 2017-2020	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the California Public Utilities Commission adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the California Public Utilities Commission and annual procurement reports with the California Energy Commission.

[10] A REC can be sold either "bundled" with the underlying energy or "unbundled", as a separate commodity from the energy itself, into a separate REC trading market.

The California Public Utilities Commission is in the process of an extensive rulemaking to implement the remaining requirements under SB 2 (1x).

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the California Public Utilities Commission and California Energy Commission websites.

Oregon

Oregon established the Oregon RPS with passage of Senate Bill 838 in 2007. The law, called the Oregon Renewable Energy Act[11] was adopted in June 2007 and provides a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation.

Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia. Electricity generated by a hydroelectric facility is eligible, if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

Utilities can bank RECs from qualifying resources beginning January 1, 2007 for the purpose of carrying them forward for future compliance. The RECs must be certified as eligible for the Oregon RPS by the Oregon Department of Energy and tracked in WREGIS.

In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. Qualifying solar photovoltaic systems must be at least 500 kilowatts in capacity with no single project greater than five megawatts of alternating current. Any qualifying solar photovoltaic systems that are online before January 1, 2016 will be credited with two megawatt-hours for every one megawatt-hour generated. The Oregon Public Utility Commission determined that PacifiCorp's share of the Oregon Solar Initiative is 8.7 megawatts.

[11] http://www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf

PacifiCorp files an annual RPS compliance report by June 1 of every year and in every odd year by January 1 PacifiCorp files a renewable implementation plan. PacifiCorp's compliance reports and implementation plans are made available on PacifiCorp's website[12].

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are included within Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah's governor signed Utah Senate Bill 202[13], "Energy Resource and Carbon Emission Reduction Initiative;" legislation. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity generation or a generation facility from a facility or upgrade that becomes operational on or after January 1, 1995 that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low impact hydro facility and in state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024. PacifiCorp filed a progress report on December 31, 2009. The Utah Division of Public Utilities is required to provide the Legislature with a summary report on the progress made by these electrical corporations by January 1 of the years 2011, 2016, 2021, 2025. In the Utah Division of Public Utilities' report to the Legislature, it was stated that, "Given PacifiCorp's projections of its loads and qualifying electricity for 2025, PacifiCorp is well positioned to meet a target of 20 percent renewable energy by 2025."

PacifiCorp's next Carbon Reduction Progress Report is expected to be filed by January 1, 2015.

In 2027, the legislation requires a commission report to the Utah Legislature which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand-side management programs for the customers of the utility paying the penalty.

[12] www.pacificpower.net/ORrps
[13] http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17.

Washington

In November 2006, Washington voters approved Initiative 937,[14] a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp. The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020 and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located within the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. Moreover, the only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs or a combination of both to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report demonstrating compliance with the Energy Independence Act by June 1 of every year with the Washington Utilities and Transportation Commission. PacifiCorp's compliance reports are made available on PacifiCorp's website[15].

The Washington Utilities and Transportation Commission adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

Federal Renewable Portfolio Standard

The United States Congress has considered a federal RPS or a national clean energy standard in the past several years. This type of national policy could increase investment in a broad range of renewable energy resources and advanced technologies. Proponents of a national clean energy standard argue that it would provide a range of benefits including fostering the creation of clean energy industries, creating clean energy jobs, enabling the advancement of new technologies, diversifying energy portfolio, and providing positive public health and environmental impacts. If a national clean energy standard is considered, several key challenges exist including but not limited to how a national clean energy standard can be harmonized with existing state RPS programs, balancing the benefits of the policy with the costs of such policy. However, Congress has not yet adopted a national clean energy standard.

[14] http://www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[15] www.pacificpower.net/WArps

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and participation of numerous stakeholders including agencies, Indian tribes, non-governmental organizations, and local communities and governments.

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of the Klamath River and Wallowa Falls hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary licenses from the Federal Energy Regulatory Commission (FERC). The 169 MW Klamath River hydroelectric project continues to operate under its existing license while PacifiCorp works with parties to implement a 2010 settlement agreement that would result in removal of the project. The assumed date of the removal in the IRP is January 1, 2021. The 1.1 MW Wallowa Falls project is currently undergoing the FERC relicensing process.

FERC hydroelectric relicensing is administered within a very complex regulatory framework and is an extremely political and often controversial public process. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate for those impacts. Stakeholder consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

The FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other certain criteria. The FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land-use, and aesthetics against the project's energy production benefits. However, because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, the FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority within the relicensing process to require installation of fish passage facilities (fish ladders and screens) at projects. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other leading to potentially contrary, or additive, licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in settlement negotiations with stakeholders, the results of which are submitted to the FERC for incorporation into a new license. The FERC welcomes settlement agreements into the relicensing process, and with associated recent license orders, has generally accepted agreement terms. Recently, the FERC has promoted that project owners seeking a new license do so through the Integrated Licensing Process (ILP). The ILP involves the FERC at early stages of the relicensing and seeks to resolve stakeholder issues in a timely manner.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2012, PacifiCorp had incurred approximately $49 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and/or settlement efforts continue for the Klamath River, Wallowa Falls, and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Also, new requirements from contemporary FERC orders and expected requirements from ongoing or new relicensing processes could amount to over $978 million over the 30 to 50 year terms of these orders. Such costs include capital investments, and related operations and maintenance costs made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect aquatic resources resulting in lost generation. The majority of these relicensing and settlement costs relate to PacifiCorp’s three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 5.

PacifiCorp’s Approach to Hydroelectric Relicensing

PacifiCorp continues to manage this process by pursuing interest-based resolutions and/or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting agency and others’ interests through creative solutions is the best way to achieve environmental improvement while managing costs. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

Rate Design Information

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission in Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No. 11-035-200. Generally, the goals for rate design are to reflect the costs to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. The Company currently has a number of rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design – Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through volumetric-based energy charges. Energy charges for residential customers are designed with an inclining tier rate structure such that high usage during a billing month is charged a higher rate than low usage. In this way, customers face a price signal to encourage reduced consumption. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. Currently, less than one percent of customers have opted to participate in the time-of-day rate option.

Changes in residential rate design that might facilitate IRP objectives include deploying a mandatory time-of-day rate design that reflects the higher costs of on-peak usage to all residential customers rather than a self-selected few. Time-of-day rates are discussed in more detail in Chapter 6 (Resource Options). Any changes in residential rate design to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs in order to ensure the price signals are economically efficient.

Commercial and Industrial Rate Design – Commercial and industrial rates in Utah are comprised of customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are intended to recover costs that don't vary with usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the Company offers two optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage and one that differentiates power charges by on- and off-peak usage. Currently, approximately 15 percent of the eligible customers are on the energy time-of-day option and less than one percent are on the power time-of-day option.

Changes in rate design that might facilitate IRP objectives include evaluating current rates in light of the growing interest in self generation by commercial and industrial customers, which is captured in the load forecast in IRP. Ensuring that partial requirements rates for customers with self generation that better reflect the costs of providing backup service to these customers is expected to be addressed in the Company's next general rate case. Partial requirements rate design is important so that customers face a true economic price as they make decisions regarding self generation.

Irrigation Rate Design – Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, seasonal power charge and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. Power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce their power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. In this way, customers face a price signal to encourage reduced consumption during the on-peak period when energy costs are higher. Irrigation customers also have an option to participate in a third party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the Company the right to interrupt the service to the participating customers when energy costs are higher.

Energy Imbalance Market

PacifiCorp signed a memorandum of understanding with the California Independent System Operator Corporation (ISO) February 12, 2013 to outline terms for the implementation of an energy imbalance market (EIM) by October 2014. A benefit study was completed by Energy and Environmental Economics which shows a range of benefits to PacifiCorp and the ISO in 2017 from $21.4m to $128.7m per year. The Company’s cost payable to the CAISO is a $2.1m one-time start-up and $1.3m per year on-going, in addition to internal Company costs for items such as metering, software and additional staffing.

An energy imbalance market is a five-minute market administered by a single market operator using an economic dispatch model to issue instructions to generating resources to meet the load for the entire footprint of the EIM. Market participants voluntarily bid their resources into the EIM. The market operator, in addition to providing dispatch instructions, provides five-minute locational marginal prices to the market participants to be used for settlement of the energy imbalance. Energy imbalance is the difference between the forecast load or generation and the actual load or generation. The benefits of an EIM include economic efficiency of an automated dispatch, savings due to diversity of loads and variable resources in the expanded footprint, and favorable impacts to reliability or operational risk.

Recent Resource Procurement Activities

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources and / or transact on various energy and environmental attribute products. Table 3.4 summarizes current RFP activities.

Table 3.4 – PacifiCorp’s Request for Proposal Activities

RFP	RFP Objective	Status	Issued	Completed
All Source RFP for 2016 Resource	600MW	Canceled	January 2012	October 2012

RFP	RFP Objective	Status	Issued	Completed
Demand-side Resources				
Oregon Solar 2010S	2 MW	Closed		October 2012
Oregon Solar 2013S	6.7 MW	Pending	1st Quarter 2013	December 2014
Natural Gas	Long-term physical and financial products	Open	May 2012	May 2013
Natural Gas Transportation	Firm natural gas supply to Naughton starting 2015	Pending	2nd Quarter 2013	December 2013
Natural Gas Transportation	Long-term gas transportation for Lake Side II resource	Complete	July 2011	May 2013
Renewable energy credits (Sale)	Excess system RECs	Open	Quarterly	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Open	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Open	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Open	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Open	Quarterly	Ongoing

All-Source Request for Proposals

PacifiCorp issued an all source RFP for a 2016 resource up to 600 megawatts on a system-wide basis in four categories: base load, intermediate, renewable and summer peaking, which are required to be on-line by June 2016. The RFP was issued to market in January 2012 for Utah and April 2012 for Oregon with a bid due date in May 2012. The bidders on the initial shortlists were notified in July 2012 and best and final pricing received in August 2012. As part of the all source RFP process, PacifiCorp filed an updated needs assessment in Oregon and Utah in September 2012, which included an update to the load and resource balance. For 2016, the load and resource balance was reduced, resulting in no significant resource need in 2016. As a result, PacifiCorp provided notice to terminate the all source RFP in Utah and withdrew PacifiCorp's all source RFP application in Oregon. A technical conference was held in October 2012 to explain the cancellation of the RFP.

Demand-side Resources

The comprehensive demand-side management RFP (2008 DSM RFP) released in November 2008 produced several proposals that at the time the 2011 Integrated Resource Plan (2011 IRP) was filed were still under consideration. Since that time the Company successfully implemented two proposals from the 2008 DSM RFP; a small business project facilitator proposal designed to simplify and improve participation in the Company's business programs for small business customers, and a home energy report program (HER Program). The HER program is currently available to select residential customers in the states of Utah and Washington[16]. A third proposal, a commercial and industrial curtailment program (Class 1 load control proposal), was pursued to the point of executing a contract but was cancelled in 2012 following preliminary 2013 IRP modeling results, used to inform the 2012 All Source Supply-Side Request for Proposals, which indicated the Company would not have the need for new Class 1 DSM until at least 2018.

A revised 2011 IRP Action Plan (Action Plan) was provided in January, 2012, as part of the state acknowledgement process. A new procurement in that Action Plan called for the Company to issue a system-wide request for proposal (excluding Oregon) for specific direct install/direct distribution programs targeting savings from the residential and small commercial sectors, program savings that could be delivered beginning in 2013 and help defer the need of the 2016 resource identified in the 2011 IRP. The RFP was issued in March, 2012; however, as a result of the Company's revised load and resource position, final evaluation of the short-listed proposals was suspended in the third quarter of 2012, pending the outcome of the 2013 IRP's Preferred Portfolio and revised valuation of demand side resources (updated decrement values).

Other key procurements in 2011 and 2012 included the re-procurement of delivery for the Company's residential Home Energy Savings program, Utah New Homes program, refrigerator recycling program, Idaho irrigation Energy Savers program, Utah and Wyoming Self-Direction Credit programs, Utah and Washington energy education programs, and Utah and Idaho irrigation load management programs[17].

The Company also issued a request for proposals in December, 2012, for the re-procurement of delivery services for Utah's Cool Keeper air conditioner load management program.

Oregon Solar Request for Proposal

PacifiCorp secured a 2.0 MW solar photovoltaic project in 2012 located in Lakeview, Oregon as a result of its 2010 solar RFP to meet Oregon Statute ORS 757.370 pertaining to the solar photovoltaic generating capacity standard, which requires Oregon utilities to acquire at least 20 MW (alternating current). PacifiCorp's share of the total is 8.7 MW. A second solar RFP is proposed to be issued in second quarter 2013 with resources required to be on line by December 31, 2014. The RFP will seek a total of 6.7 MW to meet PacifiCorp's remaining share of the standard. Due to the 5.0 MW limit per project under the Statute, the Company is seeking multiple projects through the RFP.

Natural Gas Transportation Request for Proposals

PacifiCorp issued a natural gas transportation RFP to secure firm natural gas transportation service to its Lake Side II power plant on July 5, 2011. The request for proposals bids were

[16] Home energy reports began being delivered in August, 2012, and following performance evaluations scheduled by June 2014 may be expanded to other company jurisdictions. The Energy Trust of Oregon in collaboration with the Company is launching a pilot in Pacific Power's service area beginning in August, 2013.

[17] The Utah and Idaho procurement included pricing for program delivery in the west, Oregon, Washington and California, pending the resource selections results of the 2013 integrated resource plan,

delivered August 15, 2011. As a result of the RFP bid evaluation, Questar Gas and Questar Pipeline Company were selected. Agreements were executed by both gas parties February 15, 2012 and submitted to the regulatory authorities for preapproval. The Questar Gas agreement was approved June 20, 2012, by the Utah Public Service Commission. On March 13, 2013, the Federal Energy Regulatory Commission issued an order and certificate, approving Questar Pipeline Company's application, subject to a condition that Questar Pipeline Company executes transportation agreements prior to commencing construction. The transportation agreements are on track to be signed by May 15, 2013 to meet the construction schedule.

Natural Gas Request for Proposals

Stakeholder feedback in the hedging collaborative indicated that the Company should investigate hedging some portion of its natural gas requirements for a term longer than the 36-month hedging window, as natural gas prices were perceived to be historically low. In response, the Company issued the 2012 Natural Gas RFP on May 14, 2012 for natural gas hedging and supply products ranging from four to ten years. The market response was robust, with the Company receiving hundreds of bids in a range of physical and financial products. The bids were analyzed by determining expected value to customers based on the Company's forward price and volatility curves.

Favorable bids that were Fixed-price bids or collars with terms of six years or less were selected for the initial shortlist. Credit cost was then determined for these bids. The final shortlist was then created by selecting the most favorable physical and financial bids comprising four-to-six year fixed-price bids, four-to-six year collar bids, and seven-to-ten year fixed price bids. The final shortlists showed the most benefit for customers, and were ultimately selected for refreshed pricing. On April 4, 2013, both bids were refreshed. The final shortlist was evaluate and was not favorably to the Company's forward price curves, and no deals were executed. The Company therefore entered a six-month predefined "market-monitoring window," during which the Company could continue to request refreshed bids if market movements suggest it worthwhile. Based on the experience of this RFP process, subsequent similar RFPs are expected in the future.

Natural Gas Transportation Request for Proposals

PacifiCorp will issue a natural gas transportation RFP to secure firm natural gas supply to its Naughton Unit 3 power plant after the planned plant conversion to natural gas in April 2015. The RFP is expected to be released in second quarter 2013. Final RFP schedule will be dependent upon the terms and the schedule of the plant conversion.

Renewable Energy Credit (REC) Request for Proposals

PacifiCorp issued multiple REC RFPs in 2011 and 2012 for two purposes; (i) the sale of RECs in excess of compliance needs to market and, (ii) purchase of RPS-eligible RECs to fulfill specific short-term needs to PacifiCorp's RPS obligation in Oregon, Washington, and California. The REC sale RFPs are typically issued on a quarterly basis and will continue in that format for 2013. The RPS-eligible REC purchase RFPs are issued specific to address a state compliance short.

Renewable Energy Credit (REC) Request for Proposals – Oregon
PacifiCorp issued a request for proposal to the market in December 2012, seeking offers of renewable energy credits from generation facilities that are certified by the Oregon Department of Energy as eligible for the Oregon Renewable Portfolio Standard. Procurement of unbundled RECs were completed to partially defer qualified resource additions in the future to comply with Oregon RPS requirements.

Renewable Energy Credit (REC) Request for Proposals - Washington
PacifiCorp issued a request for proposal to the market in May 2011, seeking offers of renewable energy credits from generation facilities that are eligible for Washington's renewable portfolio program (Washington Initiative 937). Procurement of unbundled RECs were completed to comply with Washington's renewable portfolio program requirements.

Renewable Energy Credit (REC) Request for Proposals - California
PacifiCorp issued a request for proposal to the market in May 2011, seeking offers of renewable energy credits from generation facilities that are eligible for California's renewable portfolio standard.

Short-term Market Power Request for Proposals

PacifiCorp issued multiple short-term market power RFPs in 2011 and 2012 to sell power for system balancing purposes. These RFPs are typically issued on a quarterly basis and will continue through 2013.

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp is obligated to plan for and meet its customers' future needs, despite uncertainties surrounding environmental and emissions regulations and potential new renewable resource requirements. Regardless of future policy direction, the Company's planned transmission projects are well aligned to respond to changing policy direction, comply with increasing reliability requirements while providing sufficient flexibility to ensure investments cost-effectively and reliably meet its customers' future needs.
- Given the long periods of time necessary to site, permit and construct major new transmission lines, these projects need to be planned well in advance and developed in time to meet customer need.
- The Company's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and are responsive to commission and stakeholder requests for a robust evaluation process and criteria for evaluating transmission additions.
- A System Operational and Reliability Benefits Tool (SBT) has been developed to measure the benefits associated with transmission that are incremental to those benefits measured by traditional IRP modeling tools.
- PacifiCorp requests acknowledgment of its plan to construct the Sigurd to Red Butte transmission project (Energy Gateway Segment G) based on the regulatory and compliance requirements driving the project's need and timing, and supported by the project's benefits as quantified using the SBT.
- While construction of future Energy Gateway segments (i.e., Gateway West and Gateway South) is beyond the scope of acknowledgement for this IRP, these segments continue to offer benefits under multiple, future resource scenarios. Thus, the Company believes continued permitting of these segments is warranted to ensure it is well positioned to advance these projects as required to meet customer need. As such, a preliminary SBT analysis summary is provided for the next major segment of Energy Gateway, the Windstar to Populus transmission project (Gateway West Segment D), to support the Company's continued permitting of Gateway West.

Introduction

PacifiCorp's bulk transmission network is designed to reliably transport electric energy from generation resources (owned generation or market purchases) to various load centers. There are several related benefits associated with a robust transmission network:

1. Reliable delivery of power to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably unscheduled outages.
3. Economic exchange of electric power among all systems and industry participants.
4. Development of economically feasible generation resources in areas where it is best suited.
5. Protection against extreme market conditions where limited transmission constrains energy supply.
6. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).
7. Increased capability and capacity to access Western energy supply markets.

PacifiCorp's transmission network is a critical component of the IRP process and is highly integrated with other transmission providers in the western United States. It has a long history of reliable service in meeting the bulk transmission needs of the region. Its purpose will become more critical in the future as energy resources become more dynamic and customer expectations continue to grow.

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on its network customers' 10-year load and resource (L&R) forecasts. Each year, the Company solicits L&R data from each of its network customers in order to determine future load and resource requirements for all transmission network customers. These customers include PacifiCorp Energy (which serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs), Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Generation & Transmission Cooperative (including Moon Lake Electric Association), Bonneville Power Administration, Basin Electric Power Cooperative, Black Hills Power and Light, and Western Area Power Administration.

The Company uses its customers' L&Rs and best available information to determine project need and investment timing. In the event that customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios and/or schedules for its project investment as appropriate. Per FERC guidelines, the Company is able to reserve transmission network capacity based on this 10-year forecast data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required for significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of load and resource forecasts.[18] A 20-year planning horizon and ability to reserve transmission capacity to meet forecasted need over that timeframe is more consistent with the time required to plan for and build large scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements.[19] The Company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where parts of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, the Company identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

IRP Feedback

In response to Commission feedback to PacifiCorp's 2011 Integrated Resource Plan, the Company committed to a revised action plan, which included the following action item for transmission:

> *In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis.*
>
> > *Develop an evaluation process and criteria for evaluating transmission additions.*
> >
> > *Review with stakeholders which transmission projects should be included and why.*
>
> *Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement.*

PacifiCorp has since developed and discussed with stakeholders a new transmission System Operational and Reliability Benefits Tool (SBT) for the purpose of identifying and quantifying transmission benefits that are not captured using traditional IRP analysis tools. Traditional means of least cost transmission planning and net power cost modeling help identify the IRP scenario with the lowest present value revenue requirement, but have historically failed to capture the full

[18] For example, PacifiCorp's application to begin the Environmental Impact Statement process for Energy Gateway West was filed with the Bureau of Land Management in late 2007 as of the 2013 IRP the federal permit has not been issued.
[19] FERC requirements; NERC standards; WECC standards.

range of benefits associated with additional transmission capabilities. The SBT identifies, measures and monetizes benefits that are incremental to those identified via models used in the IRP process.

The Company is working to improve its ability to quantify these additional transmission benefits, both in response to the directives of FERC Order No. 1000 and to feedback received from state regulators, customers and stakeholders. However, transmission benefit evaluation is no simple task. There is no “off the shelf” transmission benefit calculator readily available to the Company. Development of the SBT is a long-term objective that will continue to require adjustments based on utility industry experience, and regulator and stakeholder input. In the near term, the SBT will be used to help support transmission segments for which the Company is seeking regulatory acknowledgment, which for the 2013 IRP includes the Sigurd to Red Butte transmission project. Ultimately, this tool will be used to complement future IRP modeling efforts, compare project options and support regulatory acknowledgment by providing a more complete picture of the benefits of additional transmission capability.

In addition to a comprehensive overview of the SBT approach, this chapter provides:

- The justification supporting acknowledgement of the Company’s plan to construct the Sigurd to Red Butte transmission project, including the SBT-calculated benefits for the project;
- A preliminary SBT analysis for the Windstar to Populus transmission project (Energy Gateway Segment D) supporting the Company’s plan to continue permitting Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of how the Company’s investments in short-term system improvements have helped to maximize efficient use of the existing system and to defer the need for larger scale infrastructure investment.

System Operational and Reliability Benefits Tool

Background

Federal and state regulators, customers and stakeholders alike have expressed a need for improved methods of measuring transmission benefits and identifying beneficiaries. The traditional IRP System Optimizer and Planning and Risk models identify the IRP scenario with the lowest present value revenue requirement from an energy delivery view, but these models are not intended to capture a broader range of “day to day” operational and reliability benefits provided by transmission. A different approach is required to identify and quantify the benefits not captured by these traditional tools, and to better inform the Company’s transmission planning process in the context of integrated resource planning.

While there is no “off the shelf” transmission benefit calculator to use, there are various approaches used by other transmission planning entities that are informative. PacifiCorp, both independently and as part of the Northern Tier Transmission Group’s FERC Order No. 1000 compliance effort, looked to other regional transmission planning groups to understand how various metrics are used to evaluate transmission project benefits, impacts to existing transmission systems and customer benefits. These groups include the Southwest Power Pool, California Independent System Operator (ISO), Midwest ISO, New York ISO, ISO New England, PJM Interconnection, and Georgia Power. By no means have these groups perfected the measurement of transmission benefits, nor is there a "one size fits all" approach for assessing these benefits, but their efforts are several years in the making and, through their own stakeholder processes, they have developed and vetted several common metrics that were considered as part of PacifiCorp's efforts to develop a tool to measure transmission project benefits.

Informed by these approaches, PacifiCorp has developed the SBT to help quantify the operational and reliability benefits directly associated with new transmission projects and their integration into the existing transmission system. The metrics that comprise the SBT will continue to improve and evolve over time, with stakeholder input and through utility industry experience.

Provided below is a description of the SBT metrics the Company is working with initially, plus the SBT-calculated benefits for the Sigurd to Red Butte transmission project, for which the Company is seeking acknowledgment in this IRP.

Benefits Evaluated

Each transmission project has its own unique set of objectives, physical characteristics and benefits, and therefore may require a unique set of metrics for evaluation. A larger, more complex project may involve more metrics—or derive higher values from the same metrics—than a smaller, less complex project. For example, not all of the metrics described below derive benefit values for the Sigurd to Red Butte transmission project, whereas they may derive values for other Energy Gateway segments.

Operational Cost Savings (economic driven)
Where the IRP model topology can evaluate the specific transmission project, results from the IRP modeling process may be used to determine economic benefits (i.e. net power cost savings) of new transmission. However, in situations where the IRP model topology cannot recognize the project due to granularity limitations, a system production cost modeling program, with detailed system topology and assumptions, may be relied upon to determine the economic benefits of the specific transmission project. Alternatively, where operational cost savings are not derived specifically from production cost benefits, this metric may be used to compare operational cost savings of potential solutions. For the Sigurd to Red Butte project, the IRP model topology did not recognize the project which exists within a single IRP topology load bubble. For example, potential alternatives identified could include the addition of a new generation resource, the purchase of firm energy and wheeling costs or an alternative transmission project.

It is important to note that benefits will only be included as part of the SBT analysis to the extent they are incremental and not already captured in the production cost benefits identified through the IRP modeling process. The purpose of the SBT is to identify and measure transmission benefits not already captured via the IRP modeling—*i.e., no duplication of benefits*.

Segment Loss Savings (energy and capacity)

Energy – The addition of a new transmission line operated in parallel with an existing line(s) reduces the electrical impedance of the transmission system, resulting in lower energy line losses (megawatt-hours) over the life of the project. Depending on the amount of power flow, line loss savings can be substantial. Losses for any transmission line are determined according to the formula I^2R (where I is the current flow and R is resistance). To calculate current (I), megavolt amperes are divided by ($\sqrt{3}$ x voltage). Since the predominant flow on the Company's transmission lines is real power (megawatts), the difference when calculating current is small between megawatts (MW) and megavolt amperes (MVA). Hence, megawatt flow can be used rather than megavolt amperes as a close approximation. Factors such as line length and conductor type, material and size determine change in system impedance. The electrical impedance of parallel lines is determined by calculating an equivalent resistance ($R_{equivalent}$) before and after a transmission project is placed in service.

In the SBT analysis, the Company's assessment of energy line losses is based on actual power flow (megawatts) as a proxy for a typical year, with line flow increasing in future years as determined by network customers' load forecast submittals. Line losses are compared before and after the addition of new transmission and are calculated between the connection points, with the difference being the loss savings attributed to the new line(s). A forward energy price curve is used to monetize the value of line loss energy savings as an avoided market purchase of energy and the present value of the annual savings is then calculated.

Capacity – Lower line segment losses reduce the overall system demand and the amount of generation capacity needed to meet that demand, thereby reducing the need for new incremental generation. To determine generation capacity related savings due to reduced line segment losses, average demand savings (megawatts) are calculated for a segment using system peak flow data from previous years. To monetize these savings, the base capital cost of a combined cycle gas generating plant ($1,026 per installed megawatt)[20] is multiplied by the capacity value (megawatts) of the line loss savings and the present value of the annual savings is then calculated.

System Reliability Benefits

The SBT calculates system reliability benefits gained by adding new transmission between points in the existing system. The addition of new transmission results in new incremental capacity, but also results in improved performance of the existing system. These performance benefits are derived using Company historical transmission line outage data, for both scheduled and unscheduled line outages, and then determining the improved system performance with the new segment(s) in service during outages of a single transmission line (N-1) or multiple transmission lines (N-1-1). Benefits are measured as:

- Avoidance of transmission system capacity reductions or "derates"
  To calculate this benefit, the impact to the transmission system capacity—or "derate"—is evaluated for each line outage. These figures are then compared to the system capability with the new line segment(s) in service. The difference between capacities (megawatts) is the "derate" benefit.

[20] Cost from PacifiCorp's 2013 Integrated Resource Plan.

- Reductions in forced generator outages caused by transmission outages or limitations
  Reductions in forced generator outages is calculated using the same methodology used to calculate the "derate" benefit, but the analysis instead looks at the impacts on affected generation resources. The amount of generation that is reduced due to transmission system capacity limitations is determined with and without the new segment(s) in service. The impacts from transmission capacity reductions and the reductions in forced generator outages are then compared. To avoid double counting, only the highest megawatt value between the two impacts is selected for valuation. This megawatt value is priced using historical line outage data and a weighted average yearly price comprised of light-load and heavy-load hours using a suitable forward price curve. The present value is then determined. For calculation of multiple line outages, it is assumed that it takes a fixed amount of time—based on historical information—to restore affected generation. Since it is impossible to determine the exact time of day when an outage will occur, the megawatt value for multiple line outages is priced using the weighted heavy-load and light-load hour average of the entire forward price curve. This value is then multiplied by the probability of the outage and the present value is then determined.

- Reduced exposure to loss of firm customer load, based on calculation of avoided loss of retail revenue from customers during system outages.
  The system is evaluated with the new segment(s) in service and compared against the existing system. If the configuration with the new segment(s) enables load service that would otherwise be lost during outage conditions, this difference is the reduction in risk to customer load loss. For multiple outages (N-1-1), the probability of such an occurrence is utilized and load is assumed to be lost for two hours for each outage occurrence. The value is developed by multiplying the loss in customer demand by the probability of the outage condition by the Company's average Retail Energy Rate (dollars per kWh) for the state where the new transmission segment is placed in service. Based on this, the present value is determined.

The system performance criteria used by the Company are specified in the mandatory FERC, NERC and WECC Transmission System Planning Standards and Performance Criteria.

Customer and Regulatory Benefits

As growing demand depletes excess transmission capacity, the likelihood of impacting large industrial or commercial customers increases due to a need to curtail load to maintain a safe and reliable operating system under certain, abnormal conditions. Such circumstances can result in lost retail sales of energy, lost sales for retail customers, equipment damage, lost product, and potentially a negative economic development value for areas impacted by poor transmission system reliability. In addition, the regulatory costs following a significant outage and the resulting investigation and remediation costs can be quantified. The risk of such circumstances can be significantly reduced with new transmission capacity that supports customer load growth across the operating system.

Avoided Capital Cost

This metric considers capital investment that may be avoided by a transmission alternative, where the addition of a new transmission project resolves underlying issues identified by planning studies. In such a case, the transmission project avoids underlying upgrades for load service or reliability needs and SBT factors in the one-time capital investment as an avoided cost benefit of those projects displaced or deferred. The avoided cost of replaced or deferred investments is a commonly used metric in transmission benefit analysis.

Improved Generation Dispatch (reliability driven)
Without adequate transmission capacity, the system may not be able to fully utilize generation resources in constrained areas. As a result of this congestion, the Company may be unable to dispatch the most economic resources to meet customer needs, increasing costs to customers. New transmission infrastructure can alleviate these conditions and improve overall generation dispatch to meet system load and reliability requirements. Additionally, the same generation resources that are constrained by transmission limitations can also provide capacity benefits that may be used for system reserves through the addition of transmission capability. The SBT calculates the value of generation that may be online but not at full output and could otherwise be dispatched up to full nameplate capacity for reserves purposes when new segment(s) reduce or eliminate transmission congestion. The benefits associated with increased access to existing, dispatchable generation for reserves is calculated as the difference between the minimum unit operating limit and the amount of increased transmission capacity provided by the new segment(s) up to the maximum output of each unit. The benefit value of this generation is based on the reduced need for incremental new generation at the cost of acquiring generation or market purchases, whichever is lower.

Wheeling Revenue Opportunity
Transmission services sold to system users provides a wheeling revenue benefit derived from selling new incremental transmission capacity. The SBT reviews new incremental transmission capacity for each segment or sub-segment analyzed and identifies the value of this new capacity. The present value of the benefit attributable to wheeling revenue for each of the segments or sub-segments is based on PacifiCorp's long-term point-to-point wheeling charge (Schedules 7, 1 and 2[21]) and the new transfer capability (megawatts) not otherwise captured in the Operational Cost Savings. Incremental system capacity for each segment or sub-segment is determined by comparing the initial path transfer capability with the improved path capacity after adding the new segment(s). In cases where the available capacity has not been fully subscribed by point-to-point users, this benefit is referred to as a wheeling revenue "opportunity."

Request for Acknowledgement of Sigurd to Red Butte

The Sigurd to Red Butte transmission project is required to satisfy the Company's federal regulatory obligations to its network transmission customers under its OATT and comply with the mandatory FERC, NERC and WECC reliability standards. In addition, consistent with the Company's commitment described at the beginning of this chapter, PacifiCorp has developed—in consultation with other transmission providers, transmission planning regions, and stakeholders—a SBT for evaluating the benefits of transmission projects for which the Company seeks regulatory acknowledgment. The SBT helps identify and quantify those transmission benefits not recognized using traditional IRP analysis tools, capturing the full range of benefits associated with additional transmission. Using this tool, the Company has calculated at least $645 million in benefits associated with the Sigurd to Red Butte transmission project, and a 1.64 benefit-to-cost ratio. In March 2013, PacifiCorp obtained a certificate of public convenience and

[21] At a minimum, these rate schedules would be applicable to purchasers of long-term point-to-point transmission service.

necessity authorizing construction of the Sigurd to Red Butte transmission line from the Utah Public Service Commission. To meet regulatory reliability requirements, with demonstration of project need and showing of project benefits, the Company requests regulatory acknowledgement of the Sigurd to Red Butte transmission project.

Factors Supporting Acknowledgement

The key drivers supporting PacifiCorp's request for acknowledgement of the Sigurd to Red Butte transmission project include meeting its obligations to its network transmission customers consistent with its OATT, complying with mandatory FERC, NERC and WECC reliability standards and the positive cost benefit analysis of this project compared to other alternatives.

Improved Transmission System Capacity

The full-rated capacity of the southwest Utah transmission system, including the existing Sigurd to Three Peaks to Red Butte No. 1 – 345 kV transmission line, cannot currently provide adequate service under all expected operating conditions and customer demands. The existing Sigurd to Red Butte transmission line represents the sole connection to a major southwest Utah load area, with customer designated generation sources to this critical load isolated during line outage events. Load growth in southwestern Utah continues, and is forecasted to continue, surpassing the capability of the existing transmission system. New facilities must be constructed to provide reliable capacity for load service. Without the Sigurd to Red Butte transmission project, peak load in southwestern Utah cannot be reliably served during transmission line outages or major equipment contingencies. The Sigurd to Red Butte transmission project also supports future electrical load growth in southwestern Utah and improves the ability of the Company's transmission system to transport energy into southwest and central Utah and to high growth areas along the Wasatch Front of Salt Lake City.

Enhanced Transfer Capability to Promote Energy Transfers

Under its OATT, the Company has transmission service contract obligations for firm transmission service into and out of southwestern Utah. Indeed, the OATT obligates the Company to provide adequate and non-discriminatory network transmission service for delivery of network generation to loads. The current system supports up to 400 MW of firm energy transfers (bi-directional) between southwestern Utah and Nevada. The Company has contractual commitments and future load service requirements that cannot reliably be delivered via the transmission system existing in the area today. To meet these transfer obligations, the Company must increase the total capacity between the existing Sigurd and Red Butte substations. Following completion of the Sigurd to Red Butte project, the transfer capacity of the existing system between Utah and Nevada will increase by an additional 200 MW. This additional transmission capacity can be purchased by the Company to make off-system sales during periods when surplus energy exists, or can be purchased for use by third parties. The Sigurd to Red Butte transmission project will enable the Company to continue to meet its OATT obligations, as well as its contractual service obligations to PacifiCorp Energy, Utah Associated Municipal Power Systems, Utah Municipal Power Association, and Deseret Generation & Transmission Co-operative, Inc. The added transfer capacity is vital to the Company's continued ability to provide reliable service to these entities in the future.

Improved Transmission System Reliability

In addition to increasing system capacity, the Sigurd to Red Butte transmission project will provide needed redundancy to the existing infrastructure and substantially improve the Company's ability to provide reliable electric service to its customers in compliance with mandatory FERC, NERC and WECC reliability standards. These standards require that transmission providers evaluate all expected customer demand levels and operating conditions, and plan for adequate redundancy in their systems in order to maintain required system reliability and performance levels. It is the responsibility of the Company as the transmission provider to utilize operational history and experience to plan, design, site and construct transmission projects as required to meet system performance requirements and manage reliability, risks, and costs. Without the Sigurd to Red Butte transmission project, peak loads in southwestern Utah will not be reliably served and transmission service contract obligations will not be met. The Sigurd to Red Butte transmission project has been designed in a manner that meets the Company's system planning criteria (developed in compliance with mandatory FERC, NERC and WECC standards and criteria, and based on the Company's operational history and experience), substantially improving the Company's ability to provide reliable electric service to its customers long term and enhancing the reliability and capacity of the existing transmission system.

Sigurd to Red Butte Cost Benefit Analysis

The SBT metrics quantify the transmission benefits that are otherwise not captured within the existing IRP analysis. As applied to the Sigurd to Red Butte transmission project, for which the Company is seeking acknowledgement in this IRP, the SBT derived the following benefits and benefit-to-cost ratio.

Table 4.1 – SBT-Derived Values for Sigurd to Red Butte

* * * * * * * * * ***SBT-Derived values for Sigurd to Red Butte*** * * * * * * * * *
$645 million over 2015-2034 period, 1.64 benefit-cost ratio
Operational Cost Savings
• Energy (option at 25% of total) .... $470 million
• Third-party wheeling .... $104 million
Segment Loss Savings[22]
• Energy .... $55.5 million
• Capacity .... $14.9 million
System Reliability Benefits
• N-1 load curtailment (load over 580 MW) .... $1 million
Customer and Regulatory Benefits .... TBD
Wheeling Revenue Opportunity:
• ATC firm southbound .... $57 million
TOTAL MEASURED BENEFITS
(minus Wheeling Revenue Opportunity) .... **$645 million**
PROJECT CAPITAL COST.. $392 million[23]
PROJECT BENEFIT-TO-COST RATIO........................ 1.64
NOTE: See excel spreadsheet for detailed Sigurd to Red Butte SBT assumptions and calculations[24]

Gateway West – Continued Permitting

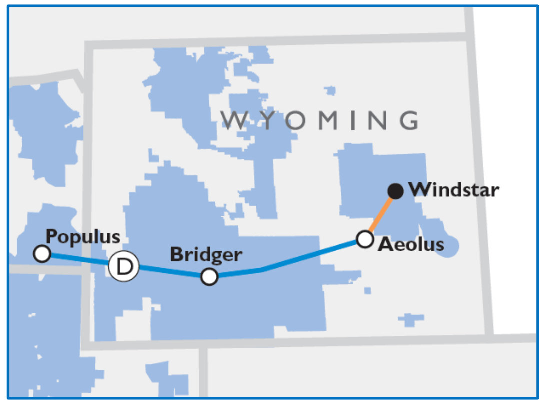
The Windstar to Populus transmission project (Energy Gateway Segment D) is the first of two planned segments of Gateway West. Given the delays experienced in the permitting process, the current project schedule for Windstar to Populus shows a delay of the in-service date to December 31, 2019. In a future IRP, the Company will support a request for acknowledgement to construct Windstar to Populus with a thorough cost-benefit analysis for the project, similar to that provided in this IRP for the Sigurd to Red Butte transmission project. While the Company is

[22] All present value calculations for Sigurd to Red Butte line losses are based on a 20-year time horizon starting in 2015, using a 6.88% discount rate, which was PacifiCorp's weighted average cost of capital at the time the analysis was undertaken.
[23] Includes fully loaded capital and related operations and maintenance costs on a 20-year time horizon starting in 2015, discounted at 6.88%.
[24] "System Benefit Tool for Sigurd to Red Butte Transmission Line (Segment G)" http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacTrans_SigurdToRedButte-SBT_4-30-13.xlsx

not requesting acknowledgement in this IRP of a plan to *construct* the Windstar to Populus project, the Company will continue to *permit* the project, and provides below a preliminary SBT analysis summary that demonstrates significant project benefits to support this plan.

Windstar to Populus

The Windstar to Populus transmission project consists of three key sections:



- A single-circuit 230 kilovolt (kV) line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation to be constructed near Medicine Bow, Wyoming;
- A single-circuit 500 kV line running approximately 140 miles from the Aeolus substation to a new annex substation near the existing Bridger substation in western Wyoming; and
- A single-circuit 500 kV line running approximately 200 miles between the new annex substation and the recently constructed Populus substation in southeast Idaho.

The project would enable the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e. reduced line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long-term.

Preliminary SBT Analysis – Windstar to Populus (Segment D)

The SBT metrics quantify the transmission benefits that are otherwise not captured within the existing IRP analysis. The footnoted excel spreadsheet provides for a detailed view of the project benefits, including operational savings as measured by the System Optimizer model[25].

The following metrics were determined to apply to Segment D and were analyzed to determine possible benefits associated with each:

[25] "System Benefit Tool for Preferred Portfolio Case 07 Energy Gateway Scenario 2 (Segment D)" http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_System-Benefits-Tool-C07_4-23-13.xlsx

Table 4.2 – Windstar to Populus Benefits Calculation

Benefits Calculation	**Case EG2-C07**
System Optimizer Analysis	$511
Avoided Transmission System Capital Cost	$151
System Reliability Benefits	$112
Improved Generation Dispatch	$39
Segment Loss Savings - Energy	$69
Segment Loss Savings - Capacity	$18
Customer and Regulatory Benefits	$249
Wheeling Revenue Opportunity	$16
Total Benefits ($m)	$1,165
Costs *($m)*	$ (934)
Net Benefit ($m, 2012$)	$ 231

Plan to Continue Permitting Gateway West

The Windstar to Populus transmission project continues to offer benefits under multiple, future resource scenarios. To ensure the Company is well positioned to advance the project as required to meet customer need, PacifiCorp believes it is prudent to continue to permit the Gateway West transmission project.

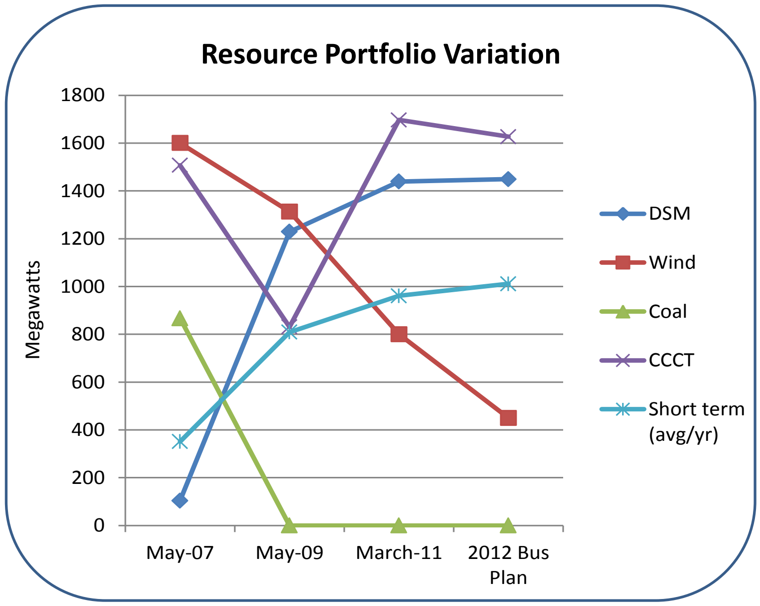
Evolution of the Energy Gateway Transmission Expansion Plan

Introduction

Given the long periods of time necessary to successfully site, permit and construct major new transmission lines, these projects need to be planned and developed in time to meet customer need. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to the Company's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until the Company's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered around the generation additions identified in the IRP. As the figure here shows, the generation resources in the Company's preferred portfolio have historically fluctuated significantly from one IRP to the next. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proven problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable transmission resource options for meeting customer need. The existing transmission system has been at capacity for several years and new capability is necessary to enable new resource development.



The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across the Company's multi-state service area. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. The Company has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the West, and include:

- ***Northwest Transmission Assessment Committee (NTAC)***
  The NTAC was the sub-regional transmission planning group representing the Northwest region, preceding Northern Tier Transmission Group and ColumbiaGrid. The NTAC developed long term transmission options for resources located within the provinces of British Columbia and Alberta, and the states of Montana, Washington and Oregon to serve Northwest loads and Northern California.

- ***Rocky Mountain Area Transmission Study***[26]
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
  - Bridger system expansion similar to Gateway West
  - Southeast Idaho to Southwest Utah expansion akin to Gateway Central and Sigurd-Red Butte
  - Improved East-West connectivity similar to Energy Gateway Segment H alternatives

> "The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices."

- ***Western Governors' Association Transmission Task Force Report***[27]
  Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection, and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high coal scenarios. Again, for PacifiCorp's system, the transmission expansion that supported these scenarios closely resembled Energy Gateway's configuration.

> "The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location."

- ***Western Regional Transmission Expansion Partnership (WRTEP)***
  The WRTEP was a group of six utilities working with four western governors' offices to evaluate the proposed Frontier Transmission Line. The Frontier Line was proposed to connect California and Nevada to Wyoming's Powder River Basin through Utah. The utilities involved were PacifiCorp, Nevada Power, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Sierra Pacific Power.

- ***Northern Tier Transmission Group Transmission Planning Reports***
  - 2007 Fast Track Project Process and Annual Planning Report[28]
  - 2008-2009 Transmission Plan[29]
  - 2010-2011 Transmission Plan[30]

  Each Energy Gateway segment was included in the 2007 Fast Track Project Process and

> "The Fast Track Project Process was used in 2007 to identify projects needed for reliability and to meet Transmission Service Requests."

[26] http://psc.state.wy.us/rmats/rmats.htm
[27] http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=97&Itemid
[28] http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=353&Itemid=31
[29] http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1020&Itemid=31
[30] http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1437&Itemid=31

has since been reevaluated as part of each Northern Tier Transmission Group biennial planning process. These are open, stakeholder processes.

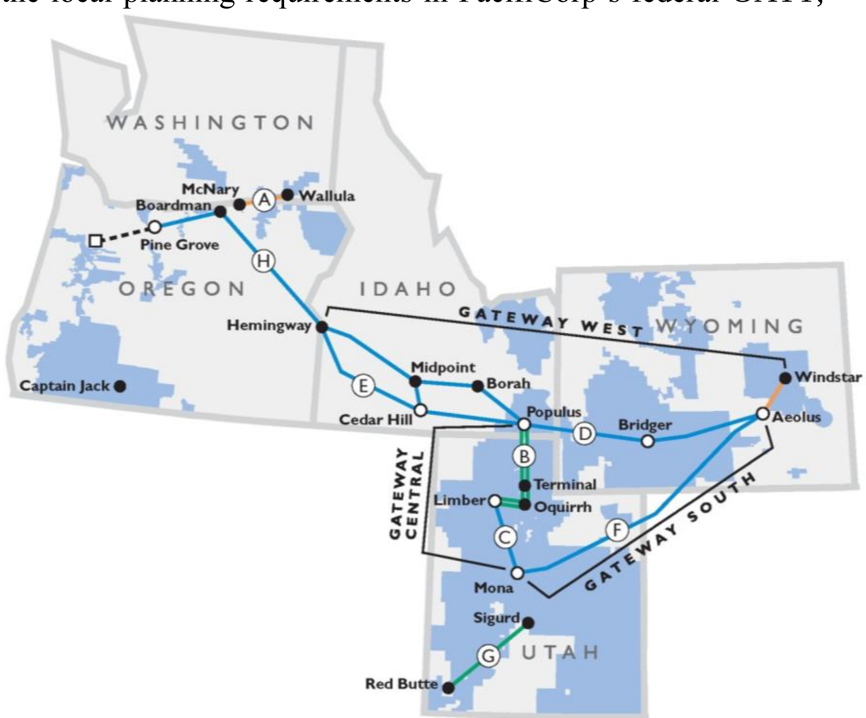
- ***WECC/TEPPC Annual Reports* and *Western Interconnection Transmission Path Utilization Studies*** [31]
  These analyses measure the historical utilization of transmission paths in the West to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments have been included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

> "Path 19 [Bridger] is the most heavily loaded WECC path in the study… Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area."

Energy Gateway Configuration

For addressing constraints identified on PacifiCorp's system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle over Utah, Idaho and Wyoming with paths extending into Oregon and Washington, and contemplates logical resource locations for the long-term based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway's announcement, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and interconnection-wide levels. In accordance with the local planning requirements in PacifiCorp's federal OATT, Attachment K, the Company has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of the Northern Tier Transmission Group (NTTG) and WECC's Transmission Expansion Policy and Planning Committee



31 http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx

(TEPPC).

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[32]

Additionally, the Project Teams conducted an extensive 18-month stakeholder process on Gateway West and Gateway South. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to establish need, assess benefits to the region, vet alternatives and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the result of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, the Company has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section on Efforts to Maximize Existing System Capability). The IRP process, as compared to transmission planning, is a frequently changing resource planning process that does not support the longer-term development needs of transmission, or the ability to implement transmission in time to meet customer need. Together, however, the IRP and transmission planning processes complement each other by helping the Company optimize the timing of its transmission and resource investments for meeting customer needs.

While the core principles for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (e.g. maximized use of energy corridors, reduced environmental impacts and improved economies of scale), the Company included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. The Company identified the costs required for this upsized system and offered transmission service contracts to queue customers. These customers,

[32] http://www.oatioasis.com/ppw/index.html

however, were unable to commit due to the upfront costs and lack of firm contracts with customers to take delivery of future generation, and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading the Company to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, the Company entered into memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power on its Boardman to Hemingway project and with Portland General Electric (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate the Company's East and West control areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a lower cost alternative.

In 2011, the Company announced the indefinite postponement of the 500 kV Gateway South segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

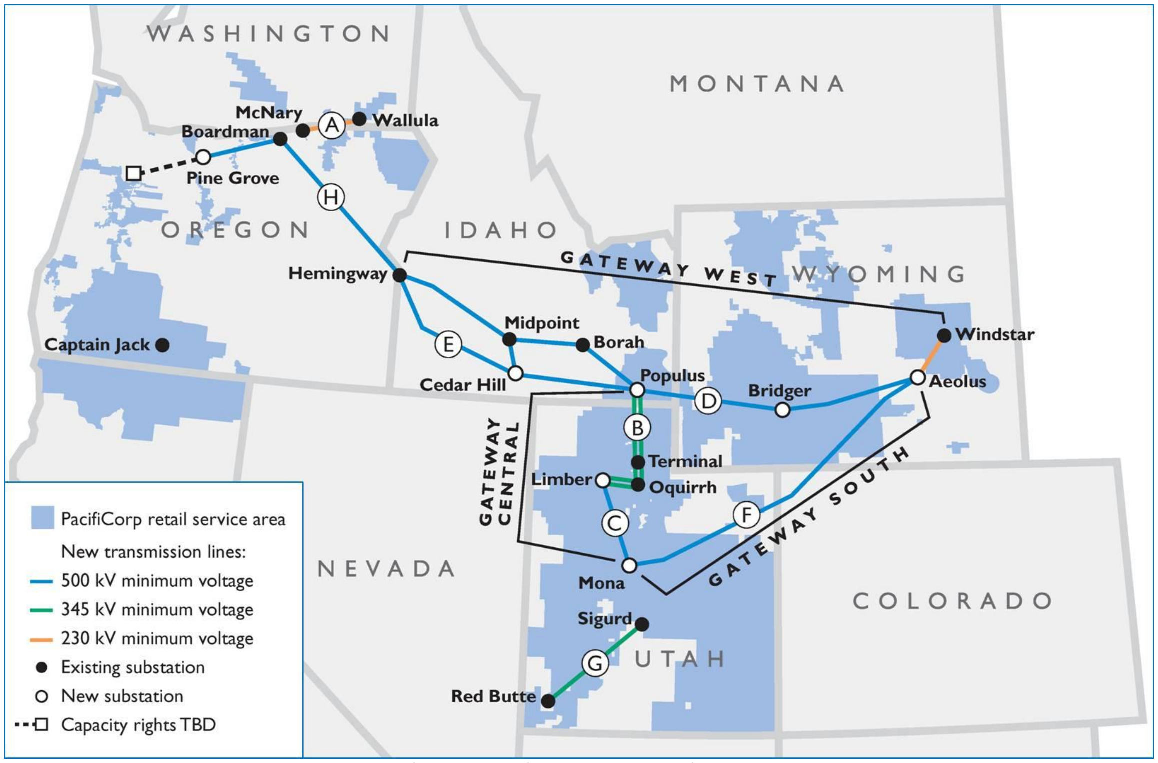
In 2012, the Company determined, due to experience with land use limitations and National Environmental Policy Act permitting requirements, that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line was feasible, and that the second new proposed 230 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from the Company's ongoing focus on meeting customer needs, taking stakeholder feedback and land use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012 the Company signed the Boardman to Hemingway Permitting Agreement with Idaho Power and Bonneville Power Administration that provides for the Company's participation through the permitting phase of the project.

In January 2013, the Company began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint-development and/or firm capacity rights into PacifiCorp's Oregon system. PacifiCorp continues to pursue potential partnership opportunities with PGE on Cascade Crossing and with Idaho Power and Bonneville Power Administration on the Boardman to Hemingway project as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack).

Finally, the timing of segments is regularly assessed and adjusted. While permitting delays have played a significant role in the adjusted timing of some segments (e.g., Gateway West and Gateway South), the Company has been proactive in deferring in-service dates due to permitting schedules, moderated load growth, changing customer needs, and system reliability improvements discussed below (e.g., Sigurd-Red Butte and Oquirrh-Terminal).

The Company will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs and its compliance with mandatory reliability standards.

Figure 4.1 – Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Segment & Name	Description	Approximate Mileage	Status[33] and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: local permitting completed • Scheduled in-service: 2013-2014*
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: construction nearing completion • Scheduled in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: June 2016*
(D) Windstar-Populus	230 kV single circuit 500 kV single circuit	400 mi	• Status: permitting underway • Scheduled in-service: 2019-2021*
(E) Populus-Hemingway	500 kV single circuit	600 mi	• Status: permitting underway • Scheduled in-service: 2020-2023*
(F) Aeolus-Mona	500 kV single circuit	400 mi	• Status: permitting underway • Scheduled in-service: 2020-2022*
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: construction started April 2013 • Scheduled in-service: June 2015
(H) West of Hemingway	500 kV single circuit	500 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: sponsor driven

** Scheduled in-service date adjusted since last IRP Update.*

[33] Status as of the filing of this IRP.

Efforts to Maximize Existing System Capability

The system analyses described above continue to confirm the need for the Energy Gateway projects, but have also been used to identify short-term improvements throughout the Company's system that have helped maximize efficient use of the existing system and defer the need for larger scale infrastructure investment. Over the past 20 to 30 years, limited new transmission capacity has been added to the system. Instead, PacifiCorp has maintained system reliability and maximized system efficiency through these smaller-scale, incremental projects.

System-wide, the Company has instituted more than 120 grid operating procedures and 17 special protection schemes to maximize the existing system capability while managing system risk. Since 2008, the Company has upgraded or rebuilt over 140 miles of existing Wyoming 230 kV transmission lines to achieve new capacity, relocated and reused more than 800 MVA of existing transformers, upgraded three major series capacitors to increase capacity, and obtained WECC approval of four major path rating upgrades. PacifiCorp recently installed equipment that will allow real time dynamic line ratings on a critical 230 kV path in Wyoming (pending WECC approval). This equipment will allow the maximum capability of the conductor, or winter rating, to be used during periods of moderate temperature in summer months, as a way to maximize capability of the existing system. Other transmission system improvements include:

- <u>Southern Utah</u>:
  - Installed 345 kV series capacitor at Pinto substation;
  - Installed shunt capacitors at Pinto and Red Butte substations;
  - Installed static var compensator at Red Butte substation;
  - Installed second 230/345 kV transformer at Harry Allen substation in Las Vegas, Nevada.

    ➔ These investments, together, helped maximize the existing system's capability, improved the Company's ability to serve growing customer loads, increased transfer capacity across WECC Paths TOT2B1 (Four Corners to Pinto, Glen Canyon to Sigurd) and TOT2C (Harry Allen to Red Butte), and reduced the risk of voltage collapse following the loss of one of the two 345 kV lines serving the Red Butte area. Specifically, these benefits include the upgrade of Path TOT2C by 300 MW, the simultaneous operation of Paths TOT2C and TOT2B1 to approved limits, and elimination of a Path TOT2B1 de-rate with growing load in southern Utah.

- <u>Wyoming</u>
  - Reconductored over 66 miles of 230 kV line between Windstar, Dave Johnston and Casper;
  - Installed shunt capacitors at Riverton, Midwest and Atlantic City substations;
  - Replaced components of the Jim Bridger transmission system Remedial Action Scheme (RAS);
  - Upgraded the series capacitor at the Borah substation and the switches in the Borah and Kinport substations;
  - Installed a dynamic line rating system on the Miners to Platte 230 kV line;
  - Installed a phase shifting transformer at the Monument substation.

➔ These investments improved reliability and helped maximize the transmission system's capabilities, providing numerous system and customer benefits:
  - Maximized transfer capability between Windstar, Dave Johnston and Casper substations during all seasons;
  - Improved the Company's ability to move Wyoming resources to PacifiCorp's customer loads;
  - Increased transfer capacity of Paths TOT4A (south and west of Casper and Dave Johnston) and TOT4B (north and west of Casper and Dave Johnston), which otherwise would have been downgraded, requiring curtailment of generation in Wyoming;
  - Increased Bridger West path rating from 2200 MW to 2400 MW, allowing integration of new resources and improved ability to serve large-customer load growth in Wyoming;
  - Reduced risk of customer impact during peak-condition operation of Jim Bridger generator;
  - Eliminated line overload conditions and generating plant output reductions.

- <u>Idaho</u>
  - Installed two 230 kV capacitor banks at the Meridian substation located in Oregon which supports an increased eastbound line rating on the Summer Lake to Hemingway line from 400 MW to 550 MW.

➔ This investment supports load growth and the ability to move additional resources and reserves from PacifiCorp's western control area to its eastern control area, supporting reliability and load service.

- <u>Oregon/Washington/California</u>
  - Participated with BPA in a number of upgrades to the California-Oregon Intertie (COI), including two new series capacitor banks at Bakeoven substation; 500 kV capacitor banks at Captain Jack and Slatt substations; reconductoring of a section of the 500 kV line; and replacement and upgrade of the Malin substation series capacitor;
  - Reconductored the 230 kV tie line between Dixonville 500 kV and Dixonville 230 kV;
  - Installed the new Nickel Mountain 230-115 kV substation and converted Line 37 in southwest Oregon from 69 to 115 kV;
  - Converted Line 3 in the Medford, Oregon area and Line 1 in the Yreka, California area from 69 kV to 115 kV;
  - Reconductored 5 miles of the Union Gap to North Park 115 kV line in Yakima Washington.

➔ These investments helped maximize the transmission system's capabilities and provided numerous system and customer benefits, including:
  - Increased the COI operating capability by 300 MW;

- Improved the Company's ability to move resources to customer loads;
- Enabled operation of the COI at its limits in the summer months, increasing the system capability by an average of 80 MW and supporting customer load growth;
- Improved reliability and support for customer load growth in southern Oregon and northern California;
- Complied with required NERC and WECC reliability standards and improved service to customers in the Yakima, Washington area.

These improvements have enabled more efficient use of the transmission system and, coupled with the recent economic sluggishness, have helped meet short-term needs. However, with projected long-term growth and the need for additional resources as depicted in our customers' load and resource forecasts, PacifiCorp's transmission system is approaching the point where no additional capacity is available, requiring additional transmission infrastructure to meet the long-term needs of our customers.

CHAPTER 5 – RESOURCE NEEDS ASSESSMENT

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances using existing resource levels, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system peak load hour.
- For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (Loads – Interruptibles – DSM). The 13-percent planning reserve margin is supported by Stochastic Loss of Load Probability Study in Appendix I.
- The system coincident peak load is forecasted to grow at a compounded average annual growth rate of 1.2 percent for 2013 through 2022. On an energy basis, PacifiCorp expects system-wide average load growth of 1.1 percent per year from 2013 through 2022.
- The Company has updated the calculation of the Load and Resource balance in-step with the upgraded IRP models. Certain items have moved from one component category to another. Sales moved from increasing obligation to reducing existing resources. Non-Owned Reserves moved from increasing reserves to reducing existing resources. Existing DSM and Interruptible contracts moved from increasing Existing Resources to reducing obligation.
- The Company projects a summer peak resource deficit of 824 MW for the PacifiCorp system beginning in 2013. The table below shows the system capacity position forecast, indicating the widening capacity deficit, which reaches 2,308 MW by 2022.
- The near-term deficit will be met by incremental demand-side management programs, and market purchases.

System	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves (Based on 13% Target)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + 13% Planning Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

Introduction

This chapter presents PacifiCorp's assessment of resource need, focusing on the first ten years of the IRP's 20-year study period, 2013 through 2022. The Company's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are addressed in detail in Appendix A. The summary level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the resource base without new additions. This comparison indicates when PacifiCorp is expected to be either deficit or surplus on both a capacity and energy basis for each year of the planning horizon.

System Coincident Peak Load Forecast

The system coincident peak load is the maximum load on the system in any hour in a one-year period. The Company's long-term load forecasts (both energy and coincident peak) for each state and the system are addressed in detail in Appendix A.

The 2013 IRP used the Company's July 2012 load forecast. Table 5.1 shows the annual coincident peak load stated in megawatts as reported in the capacity load and resource balance prior to any load reductions from energy efficiency (Class 2 DSM). The system peak load grows at a compounded average annual growth rate (CAAGR) of 1.2 percent for 2013 through 2022.

Table 5.1 – Forecasted System Coincidental Peak Load in Megawatts, Prior to Energy Efficiency Reductions

Region	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System	10,136	10,330	10,495	10,359	10,512	10,687	10,816	10,971	11,133	11,280

Existing Resources

For the forecasted 2013 summer peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 11,964 MW. Table 5.2 provides anticipated system peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2013. Note that capacity ratings in the following tables are rounded to the nearest megawatt and a column shows the Load and Resource balance capacity value at the time of system coincident peak.

Table 5.2 – 2013 Capacity Contribution at System Peak for Existing Resources

Resource Type [1/]	L&R Balance Capacity at System Peak (MW) [2/]	Percent (%)
Pulverized Coal	6,168	51.6%
Gas-CCCT	1,994	16.7%
Gas-SCCT	562	4.7%
Hydroelectric	913	7.6%
DSM [3/]	407	3.4%
Renewables	121	1.0%
Purchase [4/]	1,487	12.4%
Qualifying Facilities	171	1.4%
Interruptible	141	1.2%
Total	**11,964**	**100%**

[1/] Sales and Non-Owned Reserves are not included.
[2/] Represents the capacity available at the time of system peak used for preparation of the capacity load and resource balance. For specific definitions by resource type see the section entitled, "Load and Resource Balance Components", later in this chapter.
[3/] DSM includes existing Class 1 and Class 2 programs.
[4/] Purchases constitute contracts that do not fall into other categories such as hydroelectric, renewables, and natural gas.

Thermal Plants

Table 5.3 lists existing PacifiCorp's coal fired thermal plants and Table 5.4 lists existing natural gas fired plants. The assumed end of life dates are used for the 2013 IRP modeling of existing coal resources, additional information on methodology is in Chapter 7. The IRP confidential Volume III goes into additional analysis on coal plants.

Table 5.3 – Coal Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	L&R Balance Capacity at System Peak (MW)	Assumed End of Life Year
Carbon 1	100	Utah	67	2014
Carbon 2	100	Utah	105	2014
Cholla 4	100	Arizona	387	2042
Colstrip 3	10	Montana	74	2046
Colstrip 4	10	Montana	74	2046
Craig 1	19	Colorado	84	2034
Craig 2	19	Colorado	84	2034
Dave Johnston 1	100	Wyoming	106	2027
Dave Johnston 2	100	Wyoming	106	2027
Dave Johnston 3	100	Wyoming	220	2027
Dave Johnston 4	100	Wyoming	330	2027
Hayden 1	24	Colorado	45	2030

Plant	PacifiCorp Percentage Share (%)	State	L&R Balance Capacity at System Peak (MW)	Assumed End of Life Year
Hayden 2	13	Colorado	33	2030
Hunter 1	94	Utah	418	2042
Hunter 2	60	Utah	269	2042
Hunter 3	100	Utah	479	2042
Huntington 1	100	Utah	459	2036
Huntington 2	100	Utah	450	2036
Jim Bridger 1	67	Wyoming	354	2037
Jim Bridger 2	67	Wyoming	363	2037
Jim Bridger 3	67	Wyoming	349	2037
Jim Bridger 4	67	Wyoming	353	2037
Naughton 1	100	Wyoming	158	2029
Naughton 2	100	Wyoming	205	2029
Naughton 3*	100	Wyoming	330	2029
Wyodak	80	Wyoming	268	2039
TOTAL – Coal			**6,168**	

* Naughton 3 to repower to Natural Gas fueled generators in early 2015.

Table 5.4 – Natural Gas Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	L&R Balance Capacity at System Peak (MW)
Chehalis	100	Washington	477
Currant Creek	100	Utah	506
Gadsby 1	100	Utah	57
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	105
Gadsby 4	100	Utah	39
Gadsby 5	100	Utah	39
Gadsby 6	100	Utah	39
Hermiston 1 *	50	Oregon	233
Hermiston 2 *	50	Oregon	233
Lake Side	100	Utah	545
Lake Side 2 **	100	Utah	628
James River Cogen (CHP)	100	Washington	14
West Valley – Lease	0	Utah	200
TOTAL – Gas and Combined Heat & Power			**2,556**

* Hermiston plant 50% owned and 50% under long-term contract.
** Lake Side 2 is currently under construction with in-service date of mid-2014.

Renewables

PacifiCorp's renewable resources, presented by resource type, are described below.

Wind

PacifiCorp either owns or purchases under contract 2,186 MW of wind resources. Since the 2011 IRP Update, the Company has entered into power purchase agreements totaling 160 MW:

- Meadow Creek
  - North Point
  - Five Pine
- Butter Creek
  - High Plateau
  - Mule Hollow
  - Lower Ridge
  - Pine City

Table 5.5 shows existing wind facilities owned by PacifiCorp, while Table 5.6 shows existing wind power purchase agreements.

Table 5.5 – PacifiCorp-owned Wind Resources

Utility-Owned Wind Projects	Capacity (MW)	L&R Balance Capacity at System Peak (MW)	In-Service Year	State
Foote Creek I *	33	2	2005	WY
Leaning Juniper	101	4	2006	OR
Goodnoe Hills East Wind	94	4	2007	WA
Marengo	140	6	2007	WA
Marengo II	70	3	2008	WA
Glenrock Wind I	99	4	2008	WY
Glenrock Wind III	39	2	2008	WY
Rolling Hills Wind	99	4	2008	WY
Seven Mile Hill Wind	99	4	2008	WY
Seven Mile Hill Wind II	20	1	2008	WY
High Plains	99	4	2009	WY
McFadden Ridge 1	29	1	2009	WY
Dunlap 1	111	4	2010	WY
TOTAL – Owned Wind	**1,032**	**43**		

*Net total capacity for Foote Creek I is 40 MW.

Table 5.6 – Wind Power Purchase Agreements and Exchanges

Power Purchase Agreements / Exchanges	Capacity (MW)	L&R Balance Capacity at System Peak (MW)	In-Service Year	State
Foote Creek II	2	0	2005	WY
Foote Creek III	25	1	2005	WY
Foote Creek IV	17	1	2005	WY
Combine Hills	41	2	2003	OR
Stateline Wind	175	17	2002	OR / WA
Wolverine Creek	65	3	2005	ID
Rock River I	50	2	2006	WY
Mountain Wind Power I	60	3	2008	WY

Power Purchase Agreements / Exchanges	Capacity (MW)	L&R Balance Capacity at System Peak (MW)	In-Service Year	State
Mountain Wind Power II	80	3	2008	WY
Spanish Fork Wind Park 2	19	1	2008	UT
Three Buttes Wind Power (Duke)	99	4	2009	WY
Oregon Wind Farms I	45	3	2009	OR
Oregon Wind Farms II	20	0	2010	OR
Casper Wind	17	0	2010	WY
Top of the World	200	8	2010	WY
Power County Wind Park North	22	1	2011	ID
Power County Wind Park South	22	1	2011	ID
Meadow Creek Project – North Point *	80	3	2012	ID
Meadow Creek Project – Five Pine *	40	2	2012	ID
Butter Creek – High Plateau *	10	0	2013	OR
Butter Creek – Lower Ridge *	10	0	2013	OR
Butter Creek – Mule Hollow *	10	0	2013	OR
Butter Creek – Pine City *	10	0	2013	OR
TOTAL – Purchased Wind	**1,154**	**55**		

*New since the 2011 IRP Update.

Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus and is rated at 0.28 MW. The Company has also entered into a Qualifying Facility agreement for a 10 MW Oregon Geothermal plant scheduled to be online in late 2013.

Biomass / Biogas

Since the 2011 IRP Update, PacifiCorp has added more than 8 MW of Biogas resources. These types of resources are primarily Qualifying Facilities.

Renewables Net Metering

As of year-end 2012, PacifiCorp had 4,974 net metering customers throughout its six-state territory, generating more than 35,000 kW using solar, hydro, wind, and fuel cell technologies. About 95 percent of customer generators are solar-based, followed by wind-based generation at 4 percent of total generation.

Net metering has grown by more than 33 percent from last year. The Company averaged 114 new net metered customers a month in 2012, compared to 84 new customers per month in 2011.

Hydroelectric Generation

PacifiCorp owns 1,145 MW[34] of hydroelectric generation capacity and purchases the output from 136 MW of other hydroelectric resources. These resources account for approximately 10 percent of PacifiCorp's total generating capability, in addition to providing operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are impacted by varying water levels, licensing requirements for fish and aquatic habitat, and flood control; leading to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups as shown in Table 5.7, which reports 2013 capacity included in the load and resource balance.

Table 5.7 – Hydroelectric Contracts - Load and Resource Balance Capacities

Hydroelectric Contracts by Load and Resource Balance Category	L&R Balance Capacity at System Peak (MW)
Hydroelectric	99
Qualifying Facilities - Hydroelectric	37
Total Contracted Hydroelectric Resources	**136**

Table 5.8 provides an operational profile for each of PacifiCorp's owned hydroelectric generation facilities. The dates listed refer to a calendar year.

Table 5.8 – PacifiCorp Owned Hydroelectric Generation Facilities - Load and Resource Balance Capacities

Plant	State	L&R Balance Capacity at System Peak (MW)
West		
Big Fork	Montana	4
Clearwater 1	Oregon	15
Clearwater 2	Oregon	26
Copco 1 and 2	California	47
Fish Creek	Oregon	0
Iron Gate	California	11
JC Boyle	Oregon	15
Lemolo 1	Oregon	32
Lemolo 2	Oregon	16
Merwin	Washington	23
Rogue	Oregon	30
Small West Hydro [1/]	California / Oregon / Washington	3

[34] 2012 PacifiCorp 10-K filing shows 1,145 MW of Net Facility Capacity.

Plant	State	L&R Balance Capacity at System Peak (MW)
Soda Springs	Oregon	12
Swift 1	Washington	240
Swift 2 [2/]	Washington	72
Toketee and Slide	Oregon	26
East-Side / West-Side	Oregon	3
Yale	Washington	134
East		
Bear River	Idaho / Utah	86
Small East Hydro [3/]	Idaho / Utah / Wyoming	29
TOTAL – Hydroelectric before contracts		**824**
Hydroelectric Contracts		**136**
TOTAL – Hydroelectric		**960**

[1/] Includes Bend, Condit, Fall Creek, and Wallowa Falls

[2/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp

[3/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock

Hydroelectric Relicensing Impacts on Generation

Table 5.9 lists the estimated impacts to average annual hydro generation from FERC orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned pursuant to the Klamath Hydroelectric Settlement Agreement in the year 2020 and that the Wallowa Falls project and other projects to be relicensed in future years will receive new operating licenses, but that additional operating restrictions imposed in new licenses, such as higher bypass flow requirements, will reduce generation available from these facilities.

Table 5.9 – Estimated Impact of FERC License Renewals and Relicensing Settlement Commitments on Hydroelectric Generation

Year	Lost Generation (MWh)
2013	201,228
2014	201,228
2015	201,228
2016	201,228
2017	201,228
2018	201,228
2019	201,228
2020	918,048
2021	918,048
2022	918,048
2023	918,048
2024	918,048
2025	918,048
2026	918,048
2027	918,048
2028	918,048
2029	918,048
2030	918,048

Year	Lost Generation (MWh)
2031	918,048
2032	918,048

Demand-side Management

DSM resources/products vary in their dispatchability, reliability of results, term of load reduction benefit and persistence over time. Each has its value and place in effectively managing utility investments, resource costs and system operations. Those that have greater persistence and firmness can be reasonably relied upon as a base resource for planning purposes; those that do not are more suited as system reliability resource options. Reliability tools are used to avoid outages or high resource costs as a result of weather conditions, plant outages, market prices, and unanticipated system failures. DSM resources/products can be divided into four general classes based on their relative characteristics, the classes are:

- **Class 1 DSM: Resources from fully dispatchable or scheduled firm capacity product offerings/programs** – Class 1 DSM programs are those for which capacity savings occur as a result of active Company control or advanced scheduling. Once customers agree to participate in Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. In most cases, loads are shifted rather than avoided. Examples include residential and small commercial central air conditioner load control programs ("Cool Keeper") that are dispatchable in nature and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design and/or event noticing requirements).

- **Class 2 DSM: Resources from non-dispatchable, firm energy and capacity product offerings/programs** – Class 2 DSM programs are those for which sustainable energy and related capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their facility or home. Class 2 DSM programs generally provide financial and/or service incentives to customers to improve the efficiency of existing or new customer-owned facilities through the installation of more efficient equipment such as lighting, motors, air conditioners, or appliances or upgrading building efficiency through improved insulation levels, windows, etc. however the category has recently been expanded to include strategic energy management efforts at business facilities and home energy reports in the residential sector. The savings endure (are considered firm) over the life of the improvement or customer action. Program examples include comprehensive commercial and industrial new and retrofit energy efficiency programs ("Energy FinAnswer" and "FinAnswer Express"), refrigerator recycling programs ("See ya later, refrigerator®"), comprehensive home improvement retrofit programs ("Home Energy Saving"), strategic energy management and home energy reports.

- **Class 3 DSM: Resources from price responsive energy and capacity product offerings/programs** – Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. Savings are measured at a customer-by-customer level (via metering and/or metering data analysis against baselines), and customers are compensated or in accordance with a program's pricing parameters. As a result of their voluntary nature, savings are less predictable, making them less suitable to incorporate into resource planning exercises, at least until such time that their size and customer behavior profile provide sufficient information for a reliable diversity result for modeling and planning purposes. Savings typically only endure for the duration of the incentive offering and in many cases loads tend to be shifted rather than avoided. Program examples include large customer energy bid programs ("Energy Exchange"), time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Although the impacts of such programs may not be explicitly considered in the resource planning process however are captured naturally in long-term load growth patterns and forecasts.

- **Class 4 DSM: Non-incented behavioral based savings achieved through broad energy education and communication efforts** – Class 4 DSM programs promote reductions in energy or capacity usage through broad based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no cost actions such as conservative thermostat settings and turning off appliances, equipment and lights when not in use. The programs also are used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. Class 4 DSM programs help foster an understanding and appreciation of why utilities seek customer participation in Classes 1, 2 and 3 DSM programs. Program examples include Company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs such as "Let's turn the answers on" and "***watt***smart" campaigns. Like Class 3 resources, the impacts of such programs may not be explicitly considered in the resource planning process however are captured naturally in long-term load growth patterns and forecasts

PacifiCorp has been operating successful DSM programs since the late 1970s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the Company's DSM pursuits have been expanded in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Company investments continue to increase year on year with 2012 investments of nearly $120 million (all states). Work continues on the expansion of program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon the Company continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and Company support in pursuit of DSM resource targets. Washington's portfolio and programs continue to evolve under Initiative 937 requirements and the performance of Wyoming's program portfolio has shown increasing improvement since the latest round of program revisions were approved in November, 2011. Finally, significant changes to the Idaho and Utah Class 1 DSM portfolios are underway in an effort to improve program effectiveness and economics in those states and providing for a more viable delivery platforms for the expansion of Class 1 programs to the west side of the system as the need and value for new west-side capacity resources dictate.

The following represents a brief summary of the existing resources by class.

Class 1 Demand-side Management

Currently there are two Class 1 DSM programs running across PacifiCorp's six-state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program and Idaho's and Utah's dispatchable irrigation load management programs. In 2012 these programs accounted for over 350 MW of realized reduction from Class 1 DSM program resources under management helping the Company better manage demand during peak periods[35].

Class 2 Demand-side Management

The Company currently manages ten distinct Class 2 DSM products, many of which are offered in multiple states. In all, the combination of Class 2 DSM programs across the five states where the Company is directly responsible for delivery totals thirty-one. The cumulative historical energy and capacity savings (1992-2012) associated with Class 2 DSM program activity has accounted for over 5.4 million MWh and approximately 925 MW of non-coincident peak load reductions.

Class 3 Demand-side Management

The Company has numerous Class 3 DSM offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted block rates (Idaho, Utah and Wyoming), residential year-round inverted block rates (California, Oregon and Washington) and Energy Exchange programs (all states). System-wide, approximately 19,500 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2011.[36] All of the Company's residential customers not opting for a time-of-use rates are currently subject to seasonal or year-round inverted block rate plans.

Savings associated with these resources are captured within the Company's load forecast, with the exception of the more immediate call-to-action programs, and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate Class 3 DSM programs for applicability to long-term resource planning. As part of the development of the 2013 IRP, the Company commissioned a study by The Cadmus Group to investigate the handling of Class 3 DSM by utilities in integrated resource planning. The study, titled "Treatment of Class 3 DSM Resources in Integrated Resource Planning", is provided as Appendix D and provides valuable insights into methods used to account for the impacts of Class 3 DSM resources in integrated resource planning. The study also led to a more thorough impact assessment of the Company's existing Class 3 DSM offerings in the updated "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" ("DSM Potential Study"), the study that was used in the development of the revised DSM resource supply-curves used in the 2013 IRP. Those impacts are reflected in Table 5.10 below. In addition, the update to the DSM Potential Study expanded its analysis of the interactive effects of competing DSM resources in order to allow for modeling of all classes of DSM resources at the same time without the risks of over estimating their impacts. The DSM Potential Study is provided as Appendix D.

[35] Realized reductions vary by event (temperature and month and time dependent), cited load reduction represents the sum of the highest event performance across the three states for the two programs and account for line losses (are "at generator" values).

[36] Year-end 2011 participation data were used for the analysis in the DSM Potential Study. At the end of 2012, there were approximately 19,200 customers on time-varying rates.

As discussed in Chapter 6, five Class 3 DSM programs were provided as resource options in preliminary IRP modeling scenarios.

Class 4 Demand-side Management

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company’s long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to Class 4 DSM activity will show up in Class 1 and Class 2 DSM program results and non-program reductions in the load forecast over time.

Table 5.10 summarizes the existing DSM programs. Note that since Class 2 DSM is determined as an outcome of resource portfolio modeling and is included in the preferred portfolio, existing Class 2 DSM is shown as having zero MW[37].

Table 5.10 – Existing DSM Summary, 2013-2022

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2013-2022 Period
1	Residential/small commercial air conditioner load control	120 MW summer peak	Yes
	Irrigation load management	209 MW summer peak[38]	Yes
	Interruptible contracts	2013~ 324 MW, 2014~298 MW 2015-2022~310 MW	Yes.
2	Company and Energy Trust of Oregon programs	0 MW	No. Class 2 DSM programs are modeled as resource options in the portfolio development process, and included in the preferred portfolio.
3	Energy Exchange	0-19[39] MW (assumes no other Class 3 DSM competing products running)	No. Program is leveraged as economic and reliability resource dependent on market prices/system loads.
	Time-based pricing	27-143 MW summer peak, 19,500 customers	No. Historical behavior is captured in load forecast. Impacts estimated in 2013 Conservation Potential Assessment
	Inverted rate pricing	45-123 MW summer peak, 1.5 million residential customers	No. Historical behavior is captured in load forecast. Impacts estimated in 2013 Conservation Potential Assessment

[37] The impacts of historic acquisition rates of Class 2 DSM are backed out of the load forecast prior to modeling for new Class 2 DSM.
[38] Assumes realized irrigation load curtailment in Idaho and Utah of 171 MW and 38 MW, respectively.
[39] 2013 Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources.

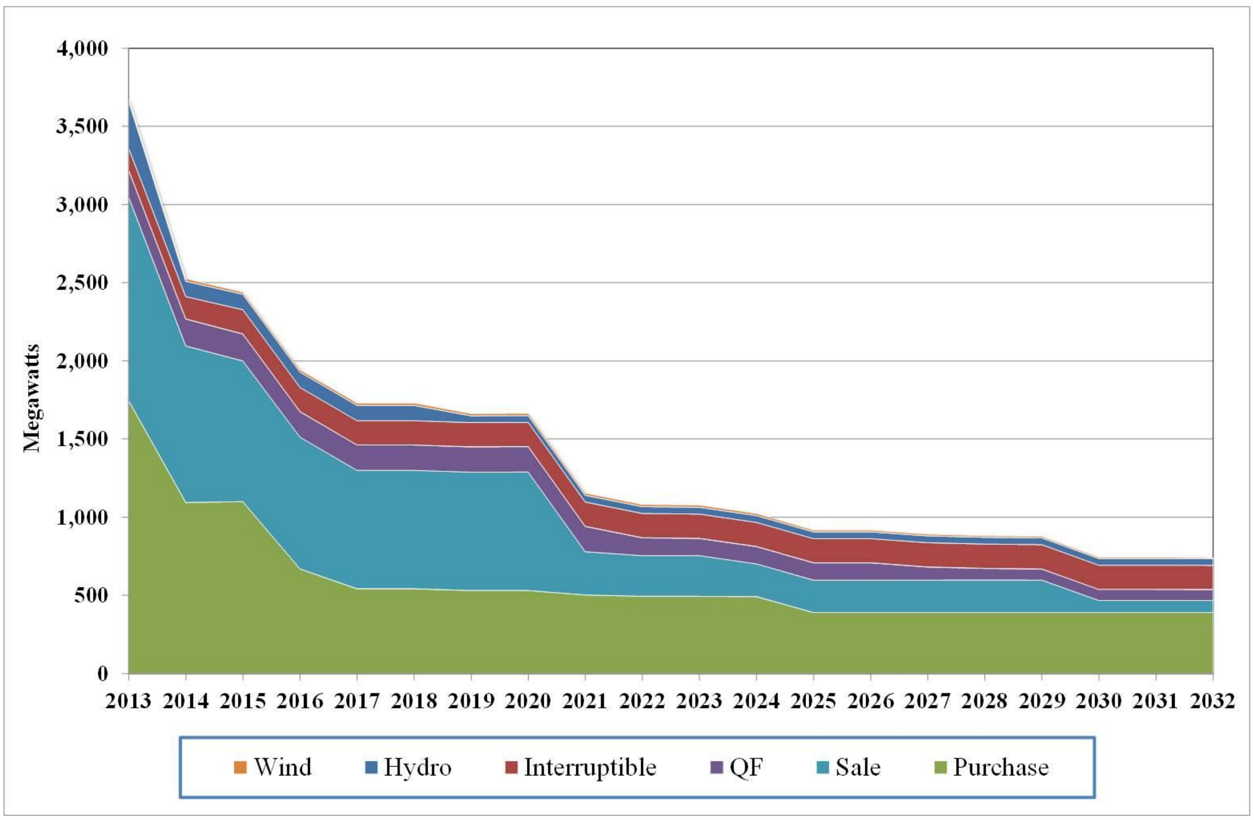
Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2013-2022 Period
4	Energy Education	MWa/MW unavailable	No. Program impacts is captured in load forecast over time and other Class 1 and 2 DSM program results.

Power Purchase Contracts

PacifiCorp obtains the remainder of its energy requirements, including any changes from expectations, through long-term firm contracts, short-term firm contracts, and spot market purchases.

Figure 5.1 presents the contract capacity in place for 2013 through 2032 as of November 2012. As shown, major capacity reductions in purchases and hydro contracts occur. (For planning purposes, PacifiCorp assumes that current qualifying facility and interruptible load contracts are extended through the end of the IRP study period.) Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 5.1 – Contract Capacity in the 2013 Load and Resource Balance



Listed below are the major contract expirations expiring between the summer 2013 and summer 2014:

- Expiring Front Office Transactions East – 300 MW
- Expiring Utah Capacity Purchase East – 200 MW
- Expiring Front Office Transactions West – 100 MW
- Expiring Bonneville Power Administration Spring / Summer Option – 150 MW
- Net decrease for other contracts – 18 MW

Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare the annual obligations with the annual capability of PacifiCorp's existing resources, absent new resource additions. This is done with respect to two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2013-2022) of the planning horizon. The peak load and load interruptible programs and load reduction DSM programs were netted together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin (PRM), and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2013-2022). The average obligation (load less DSM programs) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculation. The main component categories consist of the following: existing resources, obligation, reserves, position, and reserve margin. The Company has updated the calculation of the Load and Resource balance in-step with the upgraded IRP models. Certain items have moved from one component category to another.

Under the new calculation, there are now negative values in the table for both the resources and obligation sections. This modification provides an improvement as to how resources are modeled and represented in the categories in relation to the updated models. The four resource categories are Sales, Non-Owned Reserves, Interruptibles, and Class 1 DSM. Later in the portfolio load and resource balance Class 2 DSM follows Class 1 DSM into the obligation section. Listed below are the changes for the four categories:

- Sales moved from increasing obligation to reducing Existing Resources
- Non-Owned Reserves moved from increasing Reserves to reducing Existing Resources
- Existing Class 1 DSM moved from increasing Existing Resources to reducing obligation
- Existing Interruptible contracts moved from increasing Existing Resources to reducing obligation

For comparability to prior IRP load and resource balance tables, Table 5.11 has been provided in the prior format. This next section provides a description of these various components.

Existing Resources
A description of each of the resource categories follows:

- **Thermal**. This category includes all thermal plants that are wholly-owned or partially-owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system peak. The energy balance also counts them at maximum dependable capability, but de-rates them for forced outages and maintenance. This includes the existing fleet of 11 coal-fired plants, six natural gas-fired plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

- **Hydro**. This category includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system peak, an approach consistent with current WECC capacity reporting practices. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. The energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation, are also accounted for. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

- **Renewable.** This category comprises geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages.

  For wind and solar resources, the Company changed its method of calculating capacity contributions for wind and solar resources for this IRP. Rather than using a statistical approach to derive peak load carrying capabilities for each resource, the Company now determines aggregate peak capacity credits for each resource type by analyzing historical energy generation data for the period 2007 through 2010. For wind resources, PacifiCorp calculated the capacity credit for each year by first summing the hourly generation for all wind resources for each hour of the year and dividing the hourly generation by the aggregate nameplate capacity to get hourly capacity factors. The average capacity factor for the 100 highest summer peak hours in the year is then calculated. Finally, the wind capacity credit is multiplied by 0.90, or 90 percent, to reflect the Company’s assumption that there is a 90 percent probability that the wind resources will generate at the annual historical level in future years. The resulting annual capacity credit, averaged for the four years of historical data, is 4.2 percent. Since the Company has no historical data for solar resources, a similar set of calculations was performed based on simulated hourly solar profiles that use historic meteorological solar radiation data for five locations across the Company’s service territory. The capacity credit for solar resources is 13.6 percent assuming that most installations are optimized for energy output rather than peak capacity. See Appendix O for additional information on wind and solar peak contributions.

- **Purchase.** This includes all of the major contracts for purchases of firm capacity and energy in the PacifiCorp system. The capacity balance counts these by the maximum contract availability at time of system peak. The energy balance counts the optimum model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

- **Qualifying Facilities (QF).** All QF that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system peak availability and the energy balance counts them by optimum model dispatch. It should be noted that three of the QF resources (Kennecott, Tesoro, and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.

- **Sales**. This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view. Due to the way System Optimizer now handles the calculation of reserve margins, sales are now categorized as a resource modifier, and are applied as a decrease to resource capacity.

- **Non-owned reserves**. For this IRP, non-owned reserves capacity is now categorized as a decrease to resource capacity to represent the treatment of Non-owned reserve capacity in the of System Optimizer. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about 9 MW and 138 MW on the west and east balancing authorities, respectively. As the balancing authority, PacifiCorp is required to hold reserves for these counterparties but is not required to serve any associated loads.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less Demand-side Management and less Interruptibles. The following are descriptions of each of these components:

- **Load**. The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The system coincident peak hour is determined by summing the loads for all locations (topology bubbles with loads).

Loads reported by East and West control areas thus reflect loads at the time of PacifiCorp's coincident system peak. The energy balance counts the load as an average of monthly as well as annual time-of-day energy (MWa).

- **Dispatchable Load Control (Class 1 DSM)**. For this IRP, existing dispatchable load control program capacity is categorized as a decrease to the obligation rather than an increase to resource capacity as was done for prior IRPs. This change is in line with the treatment of DSM capacity in the latest version of System Optimizer. DSM capacity is now handled as a "load modifier", which means that it reduces load in the denominator of the planning reserve margin formula used by the model (As noted below, the reserve margin is the difference between system capability and anticipated peak demand as a percentage of the peak load.) In contrast, prior capacity balances included existing Class 1 DSM as a resource increase.

- **Interruptible**. There are three east-side load curtailment contracts in this category. These agreements with Monsanto, US Magnesium, and Nucor provide about 324 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them. As with Class 1 DSM, this resource is now categorized as a decrease to the peak load.

Reserves
The reserves are the total megawatts of planning that must be held for this load and resource balance. A description of the two types of reserves follows:

- **Planning reserves**. This is the total reserves that must be held to provide the planning reserve margin (PRM). The planning reserve margin accounts for WECC operating reserves[40], load forecast errors, and other long-term resource adequacy planning uncertainties. The following equation expresses the planning reserve requirement.

Position
The position is the resource surplus (deficit) after subtracting obligation plus required reserves from the resource total. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Reserve Margin
The reserve margin is the difference between system capability and anticipated peak demand, measured either in megawatts or as a percentage of the peak load. A positive reserve margin indicates that system capabilities exceed system obligations. Conversely, a negative reserve margin indicates that system capabilities do not meet obligations. If system capabilities equal obligations, then the reserve margin is zero. It should be pointed out that the position can be negative when the corresponding reserve margin is non-negative. This is because the reserve margin is measured relative only to obligation, while the position is measured relative to obligation plus reserves. PacifiCorp adopted a 13 percent target planning reserve margin for the 2013 IRP. Note that a resource can only serve load in another topology location if there is

[40] 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.

adequate transfer capacity. PacifiCorp captures transfer capacities as part of its capacity expansion planning process. The supporting loss of load probability study is included as Appendix I.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load hour for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system peak hours and summed as follows:

> ***Existing Resources*** *= Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities – Firm Sales – Non-owned Reserves*

The peak load, Interruptible and Class 1 DSM are netted together for each of the annual system peak hours to compute the annual peak-hour obligation:

> ***Obligation*** *= Load – Class 1 DSM – Interruptibles*

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the planning reserve margin of 13%. The formula for this calculation is the following:

> ***Planning Reserves*** *= Obligation x PRM*

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources as shown in the following formula:

> ***Capacity Position*** *= Existing Resources – (Obligation + Reserves)*

Firm capacity transfers from PacifiCorp's west to east control areas are reported for the east capacity balance, while capacity transfers from the east to west control areas are reported for the west capacity balance. Capacity transfers represent the optimized control area interchange at the time of the system coincident peak load as determined by the System Optimizer model.[41]

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2011 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Additions.** Since the 2011 IRP Update the following wind resource additions are included in existing portion of the Load and Resource balance:

[41] West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

New Qualifying Facility Wind Plants

- Meadow Creek Project – Five Pine – 40 MW
- Meadow Creek Project – North Point – 80 MW
- Lower Ridge Wind – 10 MW
- Mule Hollow Wind – 10 MW
- High Plateau Wind – 10 MW
- Pine City Wind – 10 MW

- **Solar Wind.** PacifiCorp has acquired a 2 MW photovoltaic solar plant in eastern Oregon to meet the Oregon Statute ORS 757.370, which requires the Company to acquire 8.7 MW_{ac} of qualifying photovoltaic system capacity by 2020.

  - Black Cap Solar – 2 MW

- **Coal plant turbine upgrades.** The current load and resource balance assumes 14 MW of coal plant turbine upgrades for Craig unit 2 (2 MW) and Jim Bridger Unit 2 (12 MW), completing the scheduled upgrades as noted in the 2011 IRP Update Report.

- **Construction of Lake Side 2.** PacifiCorp has begun construction of the Lake Side 2 plant in Utah. This plant is expected to have a net capacity of 645 MW.

Capacity Balance Results

PacifiCorp has updated the format for the load and resource balance table in Table 5.12. For reference, the Company has also provided table 5.11 which shows the same underlying information but in the table format used in prior IRPs. The tables show the annual capacity balances and component line items using a target planning reserve margin of 13 percent to calculate the planning reserve amount. Balances for the system as well as PacifiCorp's east and west balancing authority are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) Also note that the new Qualifying Facility wind projects listed above are reported under the Qualifying Facilities line item rather than the Renewables line item.

Table 5.11 provides a view of the Load and Resource balance using the old IRP's format for comparability to past IRP tables on the system level.

Table 5.11 – Old IRP Format: System Capacity Loads and Resources without Resource Additions

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
System										
Thermal	8,724	9,150	8,984	8,974	8,957	8,957	8,957	8,957	8,957	8,954
Hydroelectric	913	891	916	917	915	912	858	861	782	785
Class 1 DSM	407	407	407	407	407	407	407	407	407	407
Renewable	121	121	119	119	119	119	119	119	118	99
Purchase	1,487	836	842	411	298	298	287	287	259	259
Qualifying Facilities	171	172	172	162	162	162	161	162	162	114
Interruptible	141	143	155	155	155	155	155	155	155	155
Transfers	(2)	(1)	0	0	0	0	0	(2)	0	0
System Existing Resources	11,962	11,719	11,595	11,145	11,013	11,010	10,944	10,946	10,840	10,773
System Total Resources	11,962	11,719	11,595	11,145	11,013	11,010	10,944	10,946	10,840	10,773
Load	10,136	10,330	10,495	10,359	10,512	10,687	10,816	10,971	11,133	11,280
Sale	1,292	992	890	834	748	748	748	749	267	261
System Obligation	11,428	11,322	11,385	11,193	11,260	11,435	11,564	11,720	11,400	11,541
Planning reserves (13%)	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Non-owned reserves	112	112	147	147	147	147	147	147	147	147
System Reserves	1,358	1,383	1,438	1,421	1,441	1,463	1,480	1,500	1,521	1,540
System Obligation + Reserves	12,786	12,705	12,823	12,614	12,701	12,898	13,044	13,220	12,921	13,081
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)

Table 5.12 – Updated Format: System Capacity Loads and Resources without Resource Additions

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
East										
Thermal	6,200	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	137	140	140	135	135	132	135	135	135	135
Renewable	85	85	83	83	83	83	83	83	82	80
Purchase	1,005	611	611	398	285	285	285	285	257	257
Qualifying Facilities	83	73	73	73	73	73	73	73	73	25
Sale	(1,032)	(732)	(730)	(724)	(638)	(638)	(638)	(639)	(158)	(158)
Non-Owned Reserves	(103)	(103)	(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)
Transfers	750	829	737	672	678	683	1,124	1,122	1,124	706
East Existing Resources	**7,125**	**7,529**	**7,236**	**6,953**	**6,932**	**6,934**	**7,378**	**7,375**	**7,829**	**7,361**
Load	6,920	7,061	7,188	6,994	7,105	7,217	7,337	7,455	7,584	7,697
Existing Resources:										
Interruptible	(141)	(143)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
DSM	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
East obligation	**6,400**	**6,539**	**6,654**	**6,460**	**6,571**	**6,683**	**6,803**	**6,921**	**7,050**	**7,163**
Planning Reserves (13%)	832	850	865	840	854	869	884	900	917	931
East Reserves	**832**	**850**	**865**	**840**	**854**	**869**	**884**	**900**	**917**	**931**
East Obligation + Reserves	**7,232**	**7,389**	**7,519**	**7,300**	**7,425**	**7,552**	**7,687**	**7,821**	**7,967**	**8,094**
East Position	**(107)**	**140**	**(283)**	**(347)**	**(493)**	**(618)**	**(309)**	**(446)**	**(138)**	**(733)**
East Reserve Margin	11.3%	15.1%	8.7%	7.6%	5.5%	3.8%	8.5%	6.6%	11.0%	2.8%
West										
Thermal	2,524	2,524	2,524	2,520	2,503	2,503	2,503	2,503	2,503	2,500
Hydroelectric	776	751	776	782	780	780	723	726	647	650
Renewable	36	36	36	36	36	36	36	36	36	19
Purchase	482	225	231	13	13	13	2	2	2	2
Qualifying Facilities	88	99	99	89	89	89	88	89	89	89
Sale	(260)	(260)	(160)	(110)	(110)	(110)	(110)	(110)	(109)	(103)
Non-Owned Reserves	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Transfers	(752)	(830)	(737)	(672)	(678)	(683)	(1,124)	(1,124)	(1,124)	(706)
West Existing Resources	**2,885**	**2,536**	**2,760**	**2,649**	**2,624**	**2,619**	**2,109**	**2,113**	**2,035**	**2,442**
Load	3,216	3,269	3,307	3,365	3,407	3,470	3,479	3,516	3,549	3,583
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
West obligation	**3,188**	**3,241**	**3,279**	**3,337**	**3,379**	**3,442**	**3,451**	**3,488**	**3,521**	**3,555**
Planning Reserves (13%)	414	421	426	434	439	447	449	453	458	462
West Reserves	**414**	**421**	**426**	**434**	**439**	**447**	**449**	**453**	**458**	**462**
West Obligation + Reserves	**3,602**	**3,662**	**3,705**	**3,771**	**3,818**	**3,889**	**3,900**	**3,941**	**3,979**	**4,017**
West Position	**(717)**	**(1,126)**	**(945)**	**(1,122)**	**(1,194)**	**(1,270)**	**(1,791)**	**(1,828)**	**(1,944)**	**(1,575)**
West Reserve Margin	(9.5%)	(21.8%)	(15.8%)	(20.6%)	(22.3%)	(23.9%)	(38.9%)	(39.4%)	(42.2%)	(31.3%)
System										
Total Resources	10,010	10,065	9,996	9,602	9,556	9,553	9,487	9,488	9,864	9,803
Obligation	9,588	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718
Reserves	1,246	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393
Obligation + Reserves	10,834	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111
System Position	(824)	(986)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,274)	(2,081)	(2,308)
Reserve Margin	4.4%	2.9%	0.6%	(2.0%)	(4.0%)	(5.6%)	(7.5%)	(8.8%)	(6.7%)	(8.5%)

Figures 5.2 through 5.4 charts the table above for annual capacity position (resource surplus or deficits) for the system, west balancing area, and east balancing area, respectively. The east increase in 2014 is primarily due to the addition of Lake Side 2 natural gas plant.

Figure 5.2 – System Capacity Position Trend

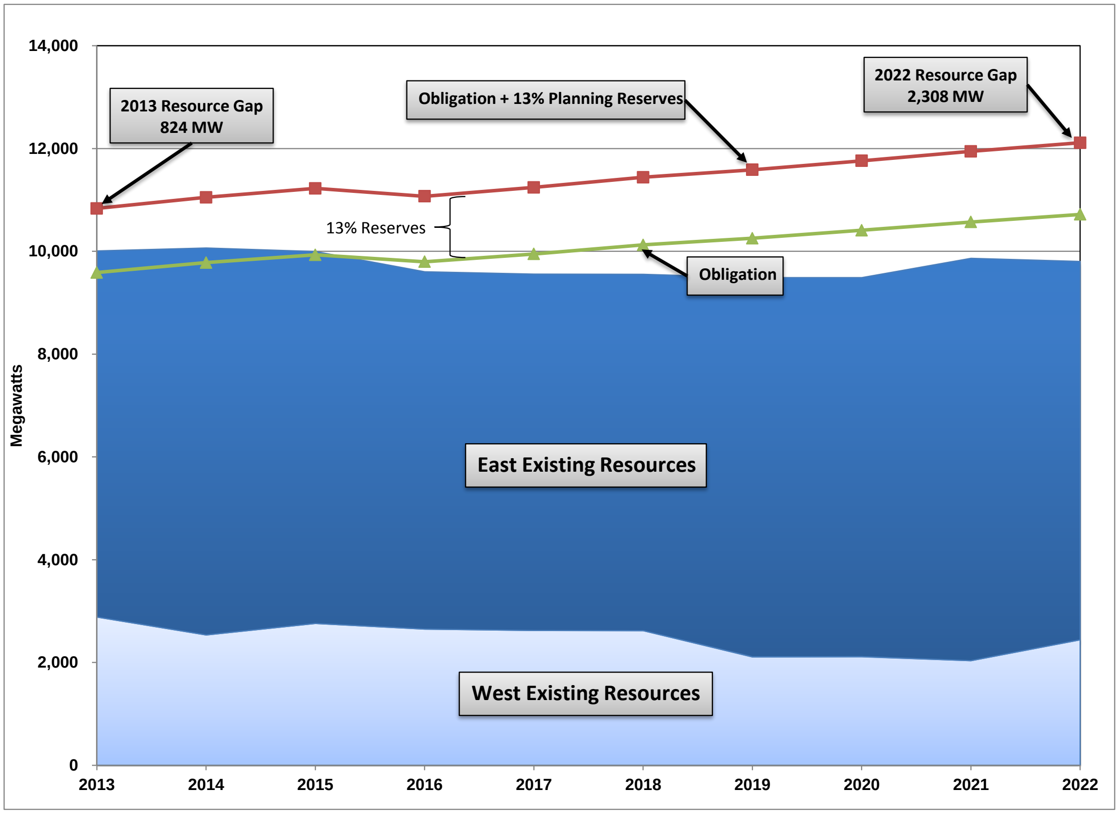


Figure 5.3 – West Capacity Position Trend

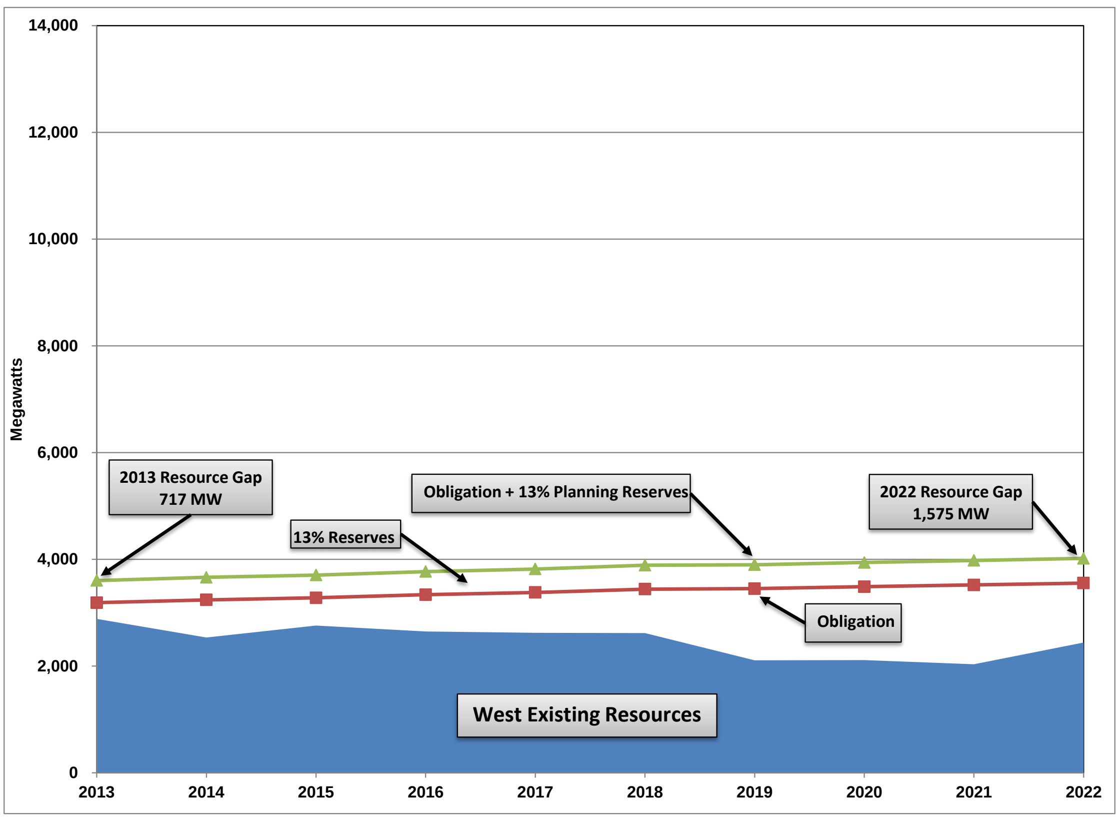
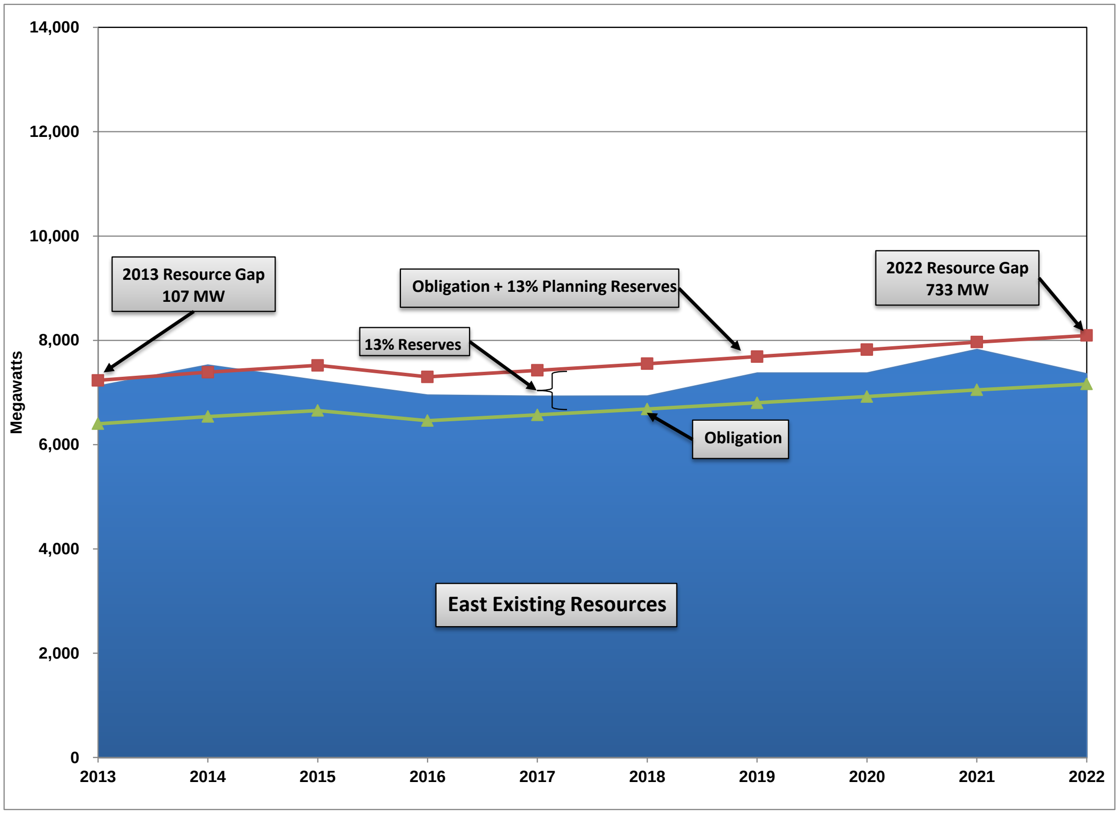


Figure 5.4 – East Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. Peaking resources such as the Gadsby units are counted only for the on-peak hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

Existing Resources = *Thermal + Hydro + Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible – Sales*

The average obligation is computed using the following formula:

Obligation = *Load + Sales*

The energy position by month and daily time block is then computed as follows:

Energy Position = *Existing Resources – Obligation – Reserve Requirements (13 percent PRM)*

Energy Balance Results

The capacity position shows how existing resources and loads balance during the coincident peak load hour of the year inclusive of a planning reserve margin. Outside of the peak hour, the Company economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, the Company can dispatch resources that in aggregate exceed then-current load obligations facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how the Company manages net power costs. Figures 5.5 through 5.7 provide for the system, west balancing area, and east balancing area, respectively, a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and current wholesale power and natural gas prices.[42] The figures show expected monthly energy production from resources during on-peak and off-peak periods in relation to load assuming no additional resources are added to PacifiCorp's system. At times, resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figures 5.5 through 5.7 also show how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018, and by 2022 available system energy falls short of monthly loads in January, July, August, and October. During off-peak periods, there are no energy shortfalls through the 2022 timeframe.

[42] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

Figure 5.5 – System Average Monthly and Annual Energy Positions

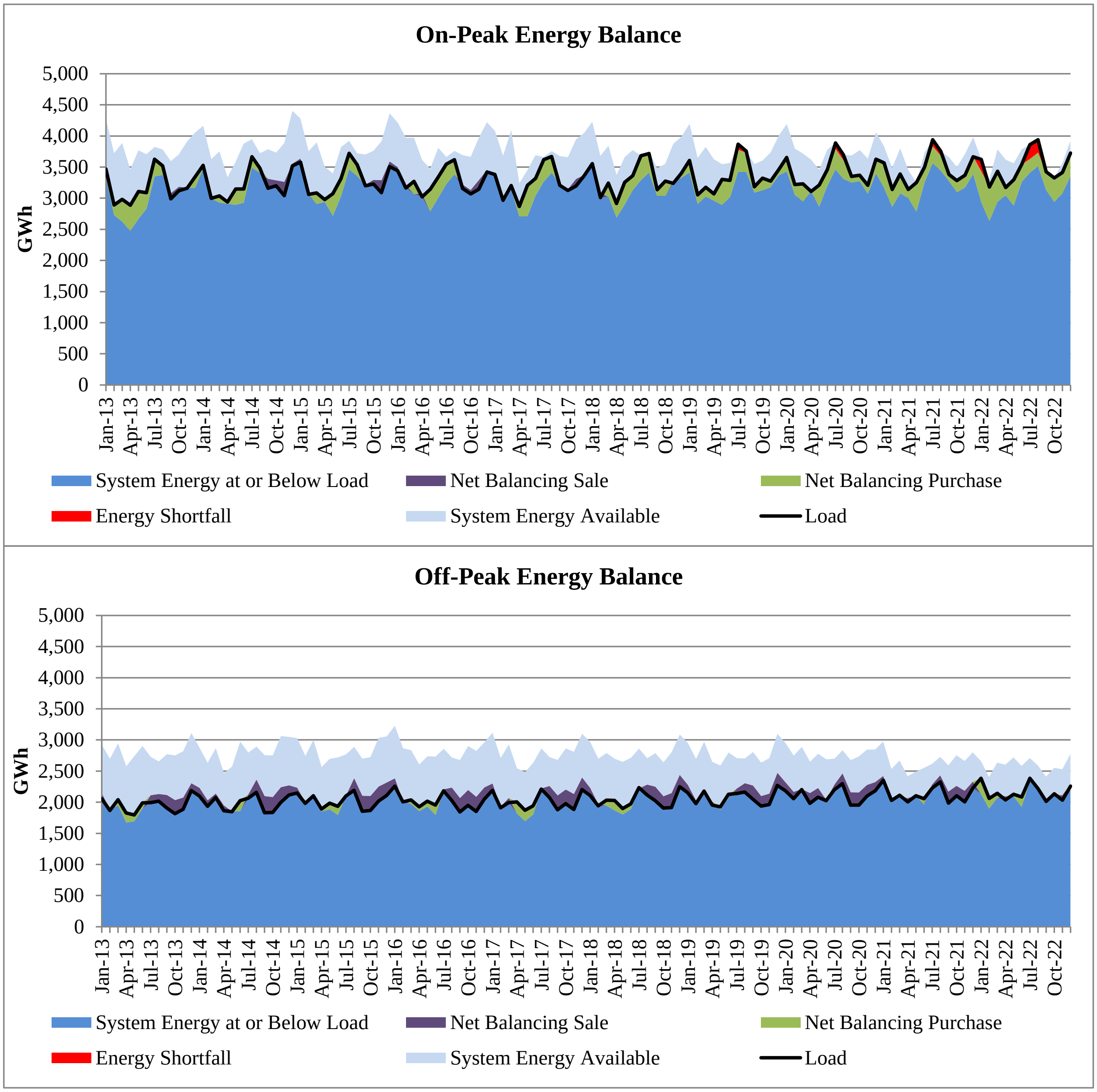


Figure 5.6 – West Average Monthly and Annual Energy Positions

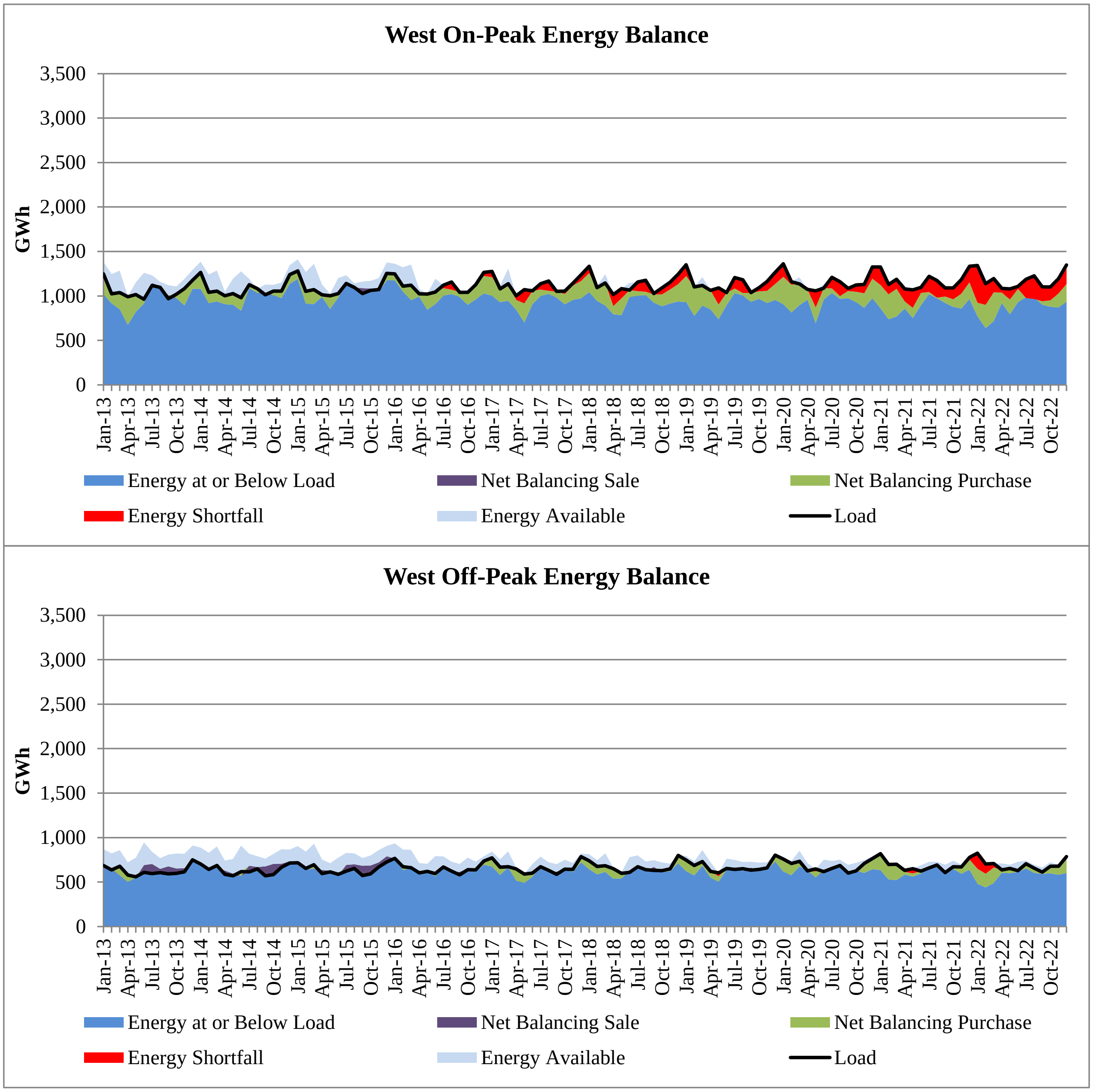
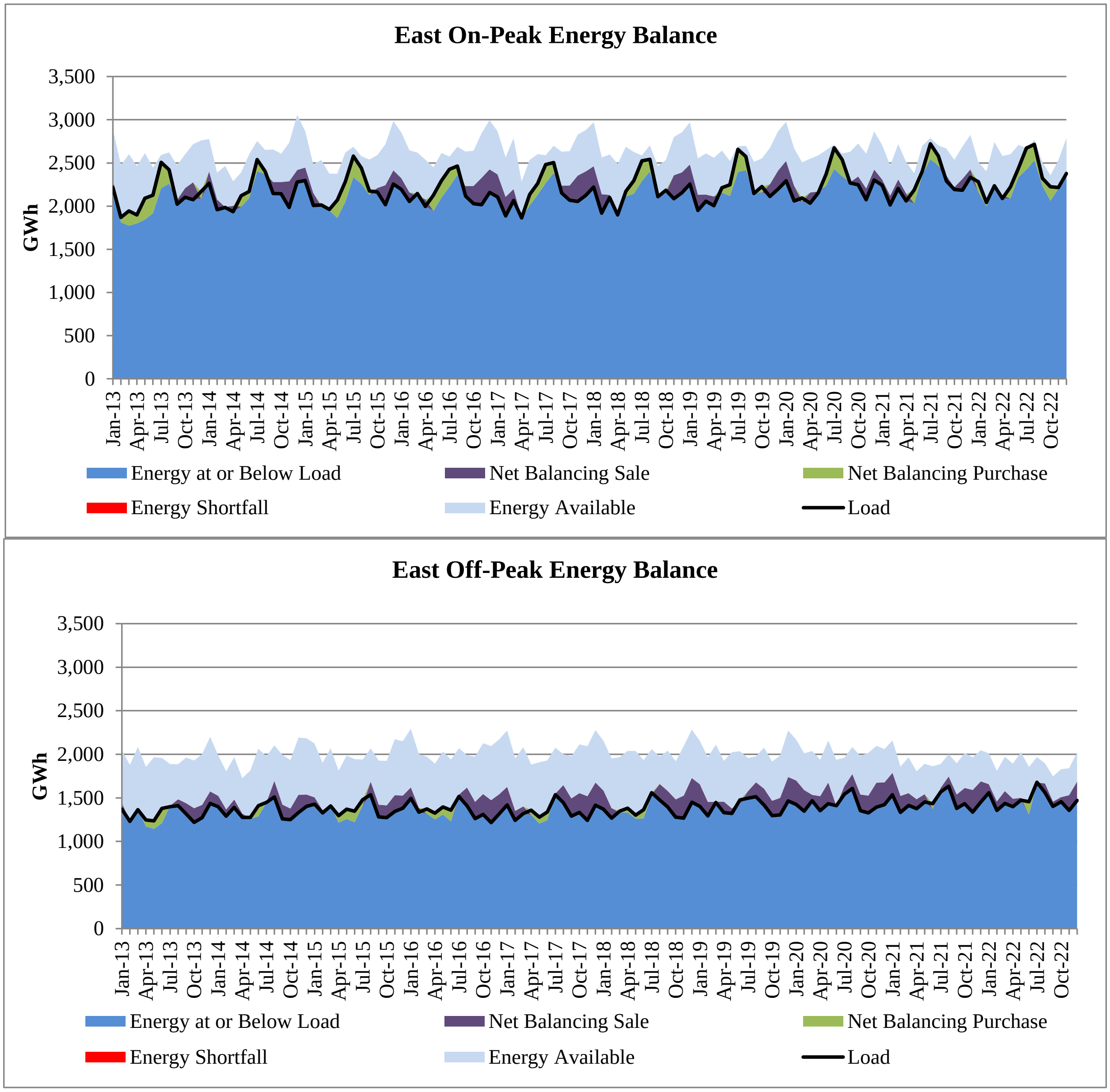


Figure 5.7 – East Average Monthly and Annual Energy Positions



Load and Resource Balance Conclusions

Without additional resources the Company projects a summer peak system resource deficit of 824 MW beginning in 2013. The near-term deficit will be filled by additional DSM programs and market purchases.

CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public meeting comments, and studies. Current economic conditions have reduced capital cost uncertainty. Long-term resource pricing, especially for emerging technologies, remains a challenge to predict.
- Resource costs have been generally stable since the previous IRP due to the economic slow-down from 2008 through 2012.
- Large utility scale solar photovoltaic options have been included in this IRP.
- Geothermal purchase power agreements (PPA) have been included as supply-side options in this IRP.
- An expanded number of combustion turbine types and configurations are provided in the current Supply Side Resource options table.
- Energy storage systems continue to be of interest with options included for advanced large batteries (one megawatt) as well as pumped hydro and compressed air energy storage.
- A 2013 resource potential study, conducted by The Cadmus Group, served as the basis for updated resource characterizations covering demand-side management (DSM) and distributed generation. The demand-side resource information was converted into supply curves by measure or product type and competed against other resource alternatives in IRP modeling.
- PacifiCorp applied cost reduction credits for energy efficiency, reflecting risk mitigation benefits, transmission & distribution investment deferral benefits, and a 10 percent market price credit for Washington and Oregon as required by the Northwest Power Act.

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of supply-side generation (utility-scaled and distributed resources), DSM programs, transmission resources, and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

Supply-side Resources

The list of supply-side resource options has been updated to reflect the realities evidenced through permitting, internally-generated studies, and externally-commissioned studies undertaken to better understand the details of available generation resources. Capital costs, in general, have remained stable due to recessionary economic conditions in 2008-2009 and a very gradual recovery experienced in 2010-2012. Natural gas-fueled plants are expected to fulfill the current and expected base-load obligations to meet customer needs and therefore natural gas-fueled resources have received a significant level of attention. A variety of gas-fueled generating resources were selected after consultation with major suppliers, large engineering-consulting firms, and primary stakeholders. New coal-fueled resources did not receive as much focus during this cycle due to ongoing environmental permitting and sociopolitical obstacles for siting new coal-fueled generation. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a flat to slightly increasing cost trend in the past two years. Certain alternative (i.e. non-fossil-fuel) energy resources such as wind and solar received greater emphasis during this review cycle compared to prior reviews. Specifically, additional solar and wind resource options have been included in the analysis compared to the previous IRP to capture cost and performance differences across different regions within the service territory. Additional solar resources include utility-size photovoltaic systems (PV) utilizing both fixed and single axis tracking. Energy storage options of at least one megawatt continue to be of interest among the stakeholders, with options analyzed for large pumped hydro projects, as well as advanced battery, fly wheel and compressed air energy storage projects.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2011 IRP. This resource list was reviewed and modified to reflect stakeholder input, environmental factors, cost dynamics, and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the Supply Side Resource table:

- Recent (2012) third-party, cost and performance estimates;
- Prior third-party, cost and performance studies or updated earlier estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent Requests for Proposals and Requests for Information.

Recent third-party engineering information from original equipment manufacturers were used to develop capital, operating and maintenance costs, performance and operating characteristics and planned outage cycle estimates. Engineering-consultants or government agencies have access to this data based on prior research studies, academia, actual installations, and direct information exchanges with original equipment manufacturers. Examples of this type of effort include the 2012 Black & Veatch estimates prepared for simple cycle and combined cycle options and the 2012 HDR Engineering (HDR) study of various storage technologies.

Prior studies include studies prepared by others but not specifically for the Integrated Resource Plan process, and include similar types of cost and performance data provided in the Supply Side Resource table. This information includes publicly available engineering and government agency reports. Examples of this type of study include the United States Department of Energy's 2011 Wind Technologies Market Report.

PacifiCorp or industry installations provide a solid basis for capital/maintenance costs and operating histories. Performance characteristics were adjusted to site-specific conditions identified in the Supply Side Resource Table. For instance, the capacity of combustion turbine based resources varies with elevation and ambient temperature and, to a lesser extent, relative humidity. Adjustments were made for site-specific elevations of actual plants to more generic, regional elevations for future resources. Examples of actual PacifiCorp installations that were used to develop the cost and performance information provided in the Supply Side Resource table include the Gadsby GE LM6000PC peaking units, the Lake Side 1 combined cycle plant and PacifiCorp's recent Black Cap solar photovoltaic project in Oregon.

Potential PacifiCorp resources also provide a source for cost and performance data. As with the actual installations, performance data was adjusted to match site conditions. Examples of potential or under-construction resources that have been used in developing information in the Supply Side Resource table include the Lake Side 2 combined cycle plant, the Vogtle Nuclear Plant currently under construction in Georgia, as well as the proposed McFadden Ridge 2 Wind Plant and 12-Mile Hill Wind Plant sites.

Recent Requests for Information (RFI) and Requests for Proposals (RFP) also provide a useful source of cost and performance data. In these cases, original equipment manufacturers provided technology specific information. Examples of RFIs informing the Supply Side Resource Table include a Greenfield geothermal site data solicitation for the "Generic Geothermal PPA 90% CF" option and the Wind Capacity Factor Assumptions RFI for different state-specific wind resource options.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many generation options is relatively high. Various factors contribute to this uncertainty, including the relatively small number of facilities that have been built, especially for new and emerging technologies, as well as prolonged economic uncertainty. Despite this uncertainty, the cost profile between the last IRP and the current IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices in the last year. This same information was presented in the 2011 IRP and the end data from that chart is shown in Figure 6.1. In the last year, costs have decreased slightly from higher initial costs and are currently close to costs that existed in September 2010. This is also illustrated by the long-term historical steel pricing trend as shown in Figure 6.2. The capital cost of generation resources reflect this status quo reality.

Figure 6.1 – World Carbon Steel Pricing by Type

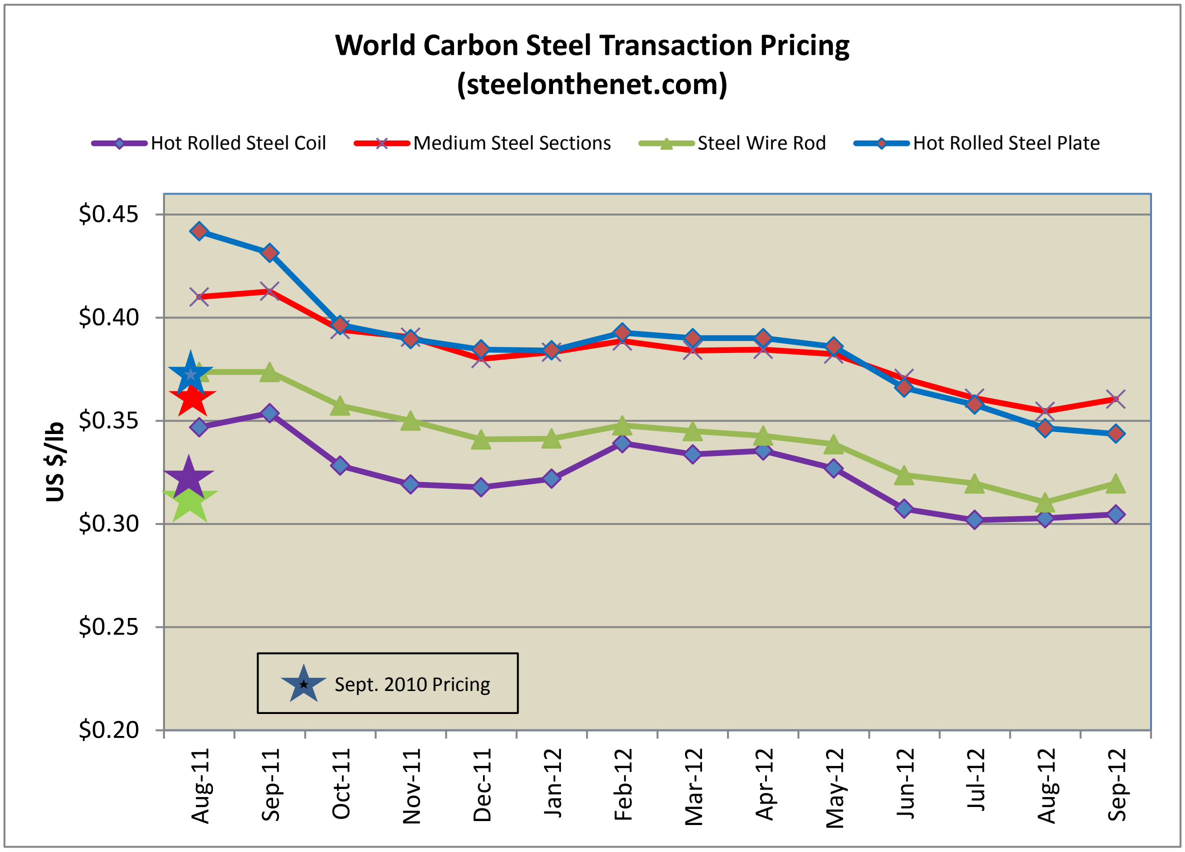
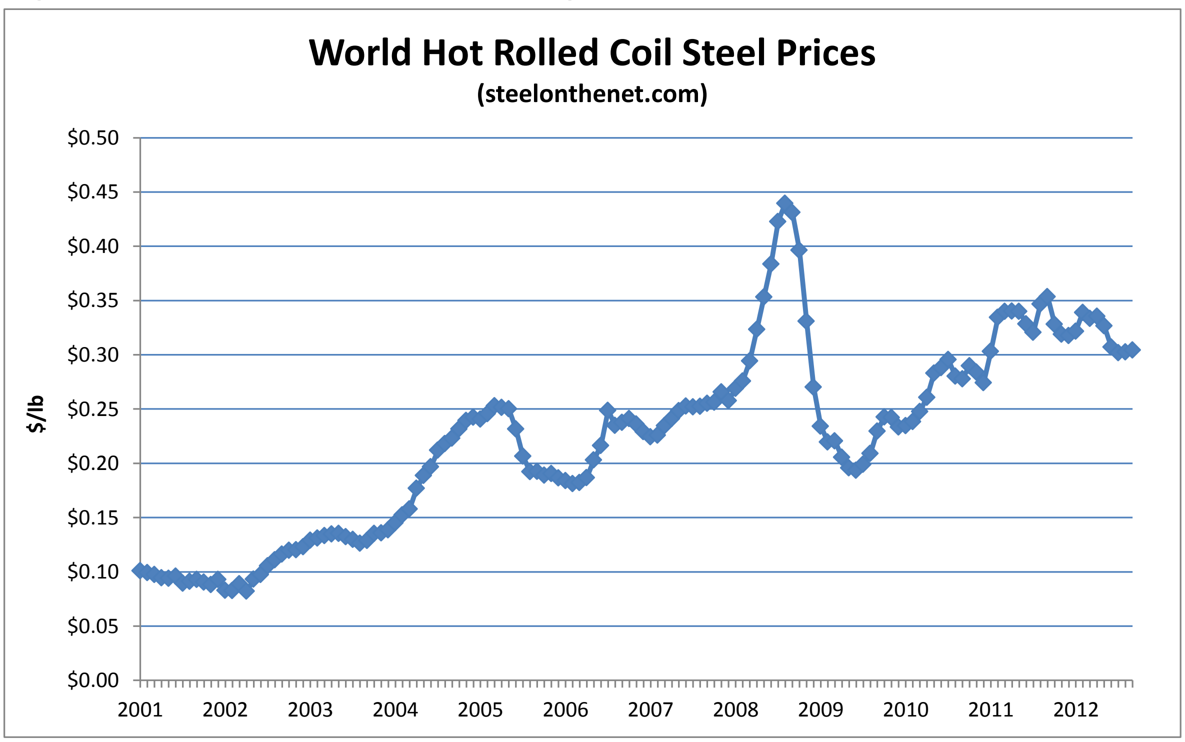


Figure 6.2 – Historic Carbon Steel Pricing



Prices for solar photovoltaic (PV) panels have fallen significantly since the 2011 IRP. Real prices are projected to continue to decline for the next several years, but uncertainty in the solar market makes it difficult to accurately predict future prices. Other technologies, such as gas turbines, and wind turbines have seen more stable prices since the 2011 IRP. Long-term resource pricing remains challenging to forecast.

Some generation technologies, such integrated gasification combined cycle (IGCC), have shown significant cost uncertainty because only a few units have been built and operated. Recent experience with cost overruns on IGCC projects such as Duke Energy's Edwardsport and Southern Company's Kemper County IGCC plants are examples that illustrate the difficulty in accurately estimating capital costs of these developing resource options. As these technologies mature and more plants are constructed, the costs of such new technologies may decrease relative to more mature options such as pulverized coal and natural gas-fueled plants.

The supply-side resource options tables do not include the potential for such capital cost reductions since the benefits are not expected to be realized until the next generation of new plants are built and operated. For example, construction and operating "experience curve" benefits for IGCC plants are not expected to be available until after their commercial operation dates. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on construction and operating experience associated with renewable generation, the Company anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the supply-side resource tables along with expected availability of each technology for commercial utilization.

Resource Options and Attributes

Table 6.1 presents cost and performance attributes for supply-side resource options designated by generic, elevation-specific regions where a resource could ultimately be located:

- ISO conditions: 0' elevation (sea level and 59 degrees F); this is used as a reference only for certain modeling purposes.
- 1,500' elevation: eastern Oregon/Washington.
- 4,500' elevation: northern Utah, specifically Salt Lake/Utah/Davis/Box Elder counties
- 5,050' elevation: central Utah, southern Idaho, central Wyoming.
- 6,500' elevation: southwestern Wyoming

Tables 6.2 and 6.3 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year, real- levelized costs for resources, stated in June 2012 dollars. The resource costs are presented for both the $0 and $16 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs.

A Glossary of Terms and a Glossary of Acronyms from the Supply Side Resource table is summarized in Table 6.4 and Table 6.5.

Table 6.1 - 2013 Supply Side Resource Table (2012$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs /MMBtu)	NOx (lbs /MMBtu)	Hg (lbs /TBtu)	CO2 (lbs /MMBtu)
Natural Gas	SCCT Aero x3, ISO	0	163	2016	30	1,081	3.50	9.88	9,739	2.6	3.9	56	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1, ISO	0	102	2016	30	1,004	2.92	15.23	8,867	2.9	3.9	78	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1, ISO	0	203	2016	35	679	8.46	7.73	9,950	2.7	3.9	10	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6, ISO	0	117	2016	30	1,204	7.40	15.61	8,447	2.5	5.0	5	0.0006	0.018	0.255	118
Natural Gas	CCCT Dry "F", 2x1, ISO	0	609	2017	40	995	2.11	6.13	6,738	2.5	3.8	11	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1, ISO	0	138	2017	40	522	0.08	0.00	8,482	0.8	3.8	11	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	372	2017	40	971	2.53	10.70	6,866	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	48	2017	40	612	0.08	0.00	8,262	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	746	2017	40	959	2.44	5.61	6,743	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	96	2017	40	600	0.07	0.00	8,105	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1, ISO	0	439	2018	40	931	2.20	9.13	6,495	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO	0	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	Intercooled SCCT Aero x1	1,500	99	2016	30	1,034	2.99	15.67	8,839	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	1,500	197	2016	35	699	8.71	7.97	9,950	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x 6	1,500	112	2016	30	1,253	7.63	16.31	8,447	2.5	3.8	5	0.0006	0.030	0.255	118
Natural Gas	CCCT Dry "F", 2x1	1,500	583	2016	40	1,039	2.18	6.43	6,738	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	1,500	138	2016	40	522	0.08	0.00	8,482	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	1,500	715	2017	40	1,000	2.54	5.86	6,773	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	96	2017	40	600	0.07	0.00	8,135	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	1,500	425	2018	40	962	2.27	9.43	6,495	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	1,500	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	SCCT Aero x3	4,250	144	2016	30	1,225	3.89	11.11	9,739	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1	4,250	91	2016	30	1,127	3.23	16.97	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	4,250	181	2016	35	762	9.48	8.67	9,950	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6	4,250	103	2016	30	1,368	8.15	18.39	8,447	2.5	5.0	5	0.0006	0.030	0.255	118
Natural Gas	CCCT Wet "F", 2x1	4,250	545	2017	40	1,104	2.87	8.58	6,666	2.5	3.8	200	0.0006	0.007	0.255	118
Natural Gas	CCCT Wet "F", DF, 2x1	4,250	89	2017	40	490	0.32	0.00	7,901	0.8	3.8	200	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", 1x1	5,050	255	2017	40	1,253	2.57	13.94	6,815	2.5	3.8	9	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", DF, 1x1	5,050	48	2017	40	546	0.08	0.00	8,518	0.8	3.8	9	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", 2x1	5,050	523	2017	40	1,159	2.42	7.14	6,738	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	5,050	138	2017	40	522	0.08	0.00	8,482	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 1x1	5,050	320	2017	40	1,129	2.94	12.45	6,866	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	48	2017	40	612	0.08	0.00	8,262	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	5,050	640	2017	40	1,118	2.82	6.55	6,743	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	96	2017	40	600	0.07	0.00	8,105	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	5,050	380	2018	40	1,075	2.54	10.54	6,495	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	5,050	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	SO Fuel Cell	4,500	5	2018	20	2,090	0.03	8.82	8,061	3	2	2	0.0006	0	0.255	118
Natural Gas	Intercooled SCCT Aero x1	6,500	86	2016	30	1,189	3.39	17.91	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	6,500	172	2016	35	804	10.00	9.13	9,950	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6	6,500	96	2016	30	1,469	8.60	19.03	8,447	2.5	5.0	5	0.0006	0.0295	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	6,500	617	2017	40	1,159	2.92	6.80	6,743	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	96	2017	40	600	0.07	0.00	8,105	0.8	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	6,500	368	2018	40	1,110	2.62	10.88	6,495	2.5	3.8	9	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	6,500	43	2018	40	486	0.08	0.00	8,611	0.8	3.8	9	0.0006	0.008	0.255	118

Table 6.1 - 2013 Supply Side Resource Table (2012$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs /MMBtu)	NOx (lbs /MMBtu)	Hg (lbs /TBtu)	CO2 (lbs /MMBtu)
Coal	SCPC with CCS	4,500	526	2032	40	5,410	6.71	69.22	13,087	5	5	1,004	0.009	0.070	0.022	20.5
Coal	SCPC without CCS	4,500	600	2027	40	2,992	0.96	40.65	9,106	4.6	4	600	0.005	0.070	0.022	205.4
Coal	IGCC with CCS	4,500	466	2032	40	5,238	11.28	55.78	10,823	8	7	394	0.009	0.050	0.333	20.5
Coal	IGCC without CCS	4,500	560	2027	40	3,734	8.39	42.45	8,734	8	7	361	0.013	0.059	0.333	205.4
Coal	PC CCS retrofit @ 500 MW	4,500	-139	2029	20	1,188	6.20	74.52	14,372	5	5	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2032	40	6,126	7.26	64.29	13,242	5	5	1,004	0.009	0.070	0.022	20.5
Coal	SCPC without CCS	6,500	790	2027	40	3,388	1.27	37.71	9,214	4.6	4	600	0.005	0.070	0.022	205.4
Coal	IGCC with CCS	6,500	456	2032	40	5,931	13.52	60.76	11,047	8	7	394	0.009	0.050	0.333	20.5
Coal	IGCC without CCS	6,500	548	2027	40	4,228	10.06	46.24	8,915	8	7	361	0.013	0.059	0.333	205.4
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2029	20	1,345	6.71	69.22	14,372	5	5	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2016	40	4,795	0.98	118.49	na	5	5	1453	0	0	0	0
Geothermal	Greenfield Binary 90% CF	4,500	43	2018	40	5,916	0.98	187.85	na	5	5	1453	0	0	0	0
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2016	20	n/a	110.00	n/a	na	5	5	1453	0	0	0	0
Wind	2.3 MW turbine 29% CF WA	1,500	100	2017	25	2,365	0.00	33.11	0	Included with CF		0	0	0	0	0
Wind	2.3 MW turbine 29% CF UT	4,500	100	2017	25	2,304	0.00	33.11	0	Included with CF		0	0	0	0	0
Wind	2.3 MW turbine 35% CF WY	6,500	100	2017	25	2,138	0.65	33.11	0	Included with CF		0	0	0	0	0
Wind	2.3 MW turbine 40% CF WY	6,500	200	2017	25	2,257	0.65	33.11	0	Included with CF		0	0	0	0	0
Solar	PV Thin Film 21% CF	4,500	2	2014	25	3,476	0.00	51.50	na	Included with CF		0	0	0	0	0
Solar	PV Poly-Si Fixed Tilt 22% CF	4,500	2	2014	25	3,153	0.00	51.50	na	Included with CF		0	0	0	0	0
Solar	PV Poly-Si Single Tracking 25% CF	4,500	2	2014	25	3,810	0.00	67.00	na	Included with CF		0	0	0	0	0
Solar	PV Poly-Si Fixed Tilt 28% CF	4,500	50	2015	25	2,952	0.00	27.81	na	Included with CF		0	0	0	0	0
Solar	PV Poly-Si Single Tracking 33% CF	4,500	50	2015	25	3,176	0.00	32.55	na	Included with CF		0	0	0	0	0
Solar	CSP Trough w Natural Gas	4,500	100	2015	30	5,072	0.00	64.00	11,750	Included with CF		725	0	0	0	0
Solar	CSP Tower 24% CF	4,500	100	2015	30	4,831	0.00	64.00	na	Included with CF		725	0	0	0	0
Solar	CSP Tower Molten Salt 30% CF	4,500	100	2015	30	5,796	0.00	64.00	na	Included with CF		750	0	0	0	0
Water	Hydrokinetic/Wave 40% CF	0	100	2024	20	5,539	0.00	166.17	na	na	na	0	0	0	0	0
Biomass	Forestry Byproduct	1,500	5	2017	30	3,334	0.96	40.65	10,017	5.06	4.4	660	0.1	0.2	0.4	205
Storage	Pumped Storage	4,500	1,000	2022	50	3,000	4.30	4.30	77.5%	3	1.9	0	0	0	0	0
Storage	Lithium Ion Battery	4,500	10	2015	20	8,712	0.00	27.40	91.0%	3	1.9	0	0	0	0	0
Storage	Sodium-Sulfur Battery	4,500	10	2015	20	4,400	0.00	27.40	72.5%	0.3	0	0	0	0	0	0
Storage	Vanadium RedOx Battery	4,500	10	2015	20	5,530	0.00	36.53	70.0%	2	0	0	0	0	0	0
Storage	Advanced Fly Wheel	4,500	10	2015	20	2,406	0.00	96.24	85.0%	2	0	0	0	0	0	0
Storage	CAES	4,500	557	2017	30	1,751	22.51	33.80	83.5%	3.5	3.5	0	0.001	0.011	0.255	118
Nuclear	Advanced Fission	4,500	2,236	2025	40	7,093	2.04	88.75	10,710	7.7	7.3	767	0	0	0	0
Nuclear	Modular Reactor	4,500	25	2030	40	3,390	1.02	44.38	10,710	7.7	7.3	767	0	0	0	0

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, $0 CO2 Tax

$0 CO2 Tax		Capital Cost $/kW			Fixed Cost					
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3, ISO	0	$1,081	8.428%	$91.13	9.88	1.34%	0.13	32.51	42.52	$133.65
Intercooled SCCT Aero x1, ISO	0	$1,004	8.428%	$84.61	15.23	1.40%	0.21	29.59	45.04	$129.65
SCCT Frame "F" x1, ISO	0	$679	7.954%	$53.98	7.73	1.37%	0.11	33.21	41.05	$95.02
IC Recips x6, ISO	0	$1,204	8.428%	$101.45	15.61	0.40%	0.06	28.19	43.87	$145.31
CCCT Dry "F", 2x1, ISO	0	$995	7.886%	$78.43	6.13	1.23%	0.08	22.49	28.69	$107.12
CCCT Dry "F", DF, 2x1, ISO	0	$522	7.886%	$41.13	0.00	0.00%	0.00	28.31	28.31	$69.44
CCCT Dry "G/H", 1x1, ISO	0	$971	7.886%	$76.59	10.70	1.96%	0.21	22.92	33.83	$110.42
CCCT Dry "G/H", DF, 1x1, ISO	0	$612	7.886%	$48.23	0.00	0.00%	0.00	27.58	27.58	$75.81
CCCT Dry "G/H", 2x1, ISO	0	$959	7.886%	$75.63	5.61	1.86%	0.10	22.51	28.22	$103.85
CCCT Dry "G/H", DF, 2x1, ISO	0	$600	7.886%	$47.32	0.00	0.00%	0.00	27.05	27.05	$74.37
CCCT Dry "J", Adv 1x1, ISO	0	$931	7.886%	$73.39	9.13	1.95%	0.18	21.68	30.98	$104.37
CCCT Dry "J", DF, Adv 1x1, ISO	0	$486	7.886%	$38.36	0.00	0.00%	0.00	28.74	28.74	$67.10
Intercooled SCCT Aero x1	1500	$1,034	8.428%	$87.12	15.67	1.40%	0.22	29.50	45.39	$132.51
SCCT Frame "F" x1	1500	$699	7.954%	$55.56	7.97	1.37%	0.11	33.21	41.29	$96.85
IC Recips x 6	1500	$1,253	8.428%	$105.64	16.31	0.40%	0.06	28.19	44.57	$150.21
CCCT Dry "F", 2x1	1500	$1,039	7.886%	$81.97	6.43	1.23%	0.08	22.49	29.00	$110.96
CCCT Dry "F", DF, 2x1	1500	$522	7.886%	$41.13	0.00	0.00%	0.00	28.31	28.31	$69.44
CCCT Dry "G/H", 2x1	1500	$1,000	7.886%	$78.87	5.86	1.86%	0.11	22.61	28.57	$107.45
CCCT Dry "G/H", DF, 2x1	1500	$600	7.886%	$47.32	0.00	0.00%	0.00	27.15	27.15	$74.47
CCCT Dry "J", Adv 1x1	1500	$962	7.886%	$75.83	9.43	1.95%	0.18	21.68	31.29	$107.13
CCCT Dry "J", DF, Adv 1x1	1500	$486	7.886%	$38.36	0.00	0.00%	0.00	28.74	28.74	$67.10
SCCT Aero x3	4250	$1,225	8.428%	$103.21	11.11	1.34%	0.15	21.95	33.21	$136.42
Intercooled SCCT Aero x1	4250	$1,127	8.428%	$94.97	16.97	1.40%	0.24	19.99	37.19	$132.16
SCCT Frame "F" x1	4250	$762	7.954%	$60.57	8.67	1.37%	0.12	22.43	31.22	$91.79
IC Recips x6	4250	$1,368	8.428%	$115.31	18.39	0.40%	0.07	19.04	37.50	$152.82
CCCT Wet "F", 2x1	4250	$1,104	7.886%	$87.05	8.58	0.70%	0.06	15.03	23.67	$110.71
CCCT Wet "F", DF, 2x1	4250	$490	7.886%	$38.63	0.00	0.00%	0.00	17.81	17.81	$56.44
CCCT Dry "F", 1x1	5050	$1,253	7.886%	$98.81	13.94	1.29%	0.18	15.36	29.49	$128.29
CCCT Dry "F", DF, 1x1	5050	$546	7.886%	$43.08	0.00	0.00%	0.00	19.20	19.20	$62.28
CCCT Dry "F", 2x1	5050	$1,159	7.886%	$91.37	7.14	1.23%	0.09	15.19	22.42	$113.79
CCCT Dry "F", DF, 2x1	5050	$522	7.886%	$41.13	0.00	0.00%	0.00	19.12	19.12	$60.25
CCCT Dry "G/H", 1x1	5050	$1,129	7.886%	$89.04	12.45	1.96%	0.24	15.48	28.17	$117.21
CCCT Dry "G/H", DF, 1x1	5050	$612	7.886%	$48.23	0.00	0.00%	0.00	18.62	18.62	$66.86
CCCT Dry "G/H", 2x1	5050	$1,118	7.886%	$88.16	6.55	1.86%	0.12	15.20	21.87	$110.03
CCCT Dry "G/H", DF, 2x1	5050	$600	7.886%	$47.32	0.00	0.00%	0.00	18.27	18.27	$65.59
CCCT Dry "J", Adv 1x1	5050	$1,075	7.886%	$84.74	10.54	1.95%	0.21	14.64	25.39	$110.13
CCCT Dry "J", DF, Adv 1x1	5050	$486	7.886%	$38.36	0.00	0.00%	0.00	19.41	19.41	$57.77

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, $0 CO2 Tax (Continued)

$0 CO2 Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
SCCT Aero x3, ISO	0	21%	72.65	na	472	45.97	3.50	6.67%	0.23	-	-	122.36	-	122.36
Intercooled SCCT Aero x1, ISO	0	21%	70.48	na	472	41.85	2.92	6.83%	0.20	-	-	115.45	-	115.45
SCCT Frame "F" x1, ISO	0	21%	51.65	na	472	46.97	8.46	7.80%	0.66	-	-	107.74	-	107.74
IC Recips x6, ISO	0	21%	78.99	na	472	39.87	7.40	4.33%	0.32	-	-	126.59	-	126.59
CCCT Dry "F", 2x1, ISO	0	56%	21.84	na	472	31.80	2.11	7.69%	0.16	-	-	55.91	-	55.91
CCCT Dry "F", DF, 2x1, ISO	0	16%	49.54	na	472	40.04	0.08	0.00%	0.00	-	-	89.65	-	89.65
CCCT Dry "G/H", 1x1, ISO	0	56%	22.51	na	472	32.41	2.53	7.05%	0.18	-	-	57.63	-	57.63
CCCT Dry "G/H", DF, 1x1, ISO	0	16%	54.09	na	472	39.00	0.08	0.00%	0.00	-	-	93.16	-	93.16
CCCT Dry "G/H", 2x1, ISO	0	56%	21.17	na	472	31.83	2.44	7.30%	0.18	-	-	55.62	-	55.62
CCCT Dry "G/H", DF, 2x1, ISO	0	16%	53.06	na	472	38.26	0.07	0.00%	0.00	-	-	91.39	-	91.39
CCCT Dry "J", Adv 1x1, ISO	0	56%	21.28	na	472	30.66	2.20	7.03%	0.15	-	-	54.29	-	54.29
CCCT Dry "J", DF, Adv 1x1, ISO	0	16%	47.87	na	472	40.65	0.08	0.00%	0.00	-	-	88.60	-	88.60
Intercooled SCCT Aero x1	1500	21%	72.03	na	472	41.72	2.99	6.83%	0.20	-	-	116.95	-	116.95
SCCT Frame "F" x1	1500	21%	52.65	na	472	46.97	8.71	7.80%	0.68	-	-	109.00	-	109.00
IC Recips x 6	1500	21%	81.65	na	472	39.87	7.63	4.48%	0.34	-	-	129.50	-	129.50
CCCT Dry "F", 2x1	1500	56%	22.62	na	472	31.80	2.18	7.67%	0.17	-	-	56.77	-	56.77
CCCT Dry "F", DF, 2x1	1500	16%	49.54	na	472	40.04	0.08	0.00%	0.00	-	-	89.66	-	89.66
CCCT Dry "G/H", 2x1	1500	56%	21.90	na	472	31.97	2.54	7.29%	0.19	-	-	56.60	-	56.60
CCCT Dry "G/H", DF, 2x1	1500	16%	53.13	na	472	38.40	0.07	0.00%	0.00	-	-	91.61	-	91.61
CCCT Dry "J", Adv 1x1	1500	56%	21.84	na	472	30.66	2.27	7.01%	0.16	-	-	54.93	-	54.93
CCCT Dry "J", DF, Adv 1x1	1500	16%	47.87	na	472	40.65	0.08	0.00%	0.00	-	-	88.60	-	88.60
SCCT Aero x3	4250	21%	74.16	na	431	42.02	3.89	6.67%	0.26	-	-	120.33	-	120.33
Intercooled SCCT Aero x1	4250	21%	71.84	na	431	38.26	3.23	6.83%	0.22	-	-	113.55	-	113.55
SCCT Frame "F" x1	4250	21%	49.90	na	431	42.93	9.48	7.80%	0.74	-	-	103.05	-	103.05
IC Recips x6	4250	21%	83.07	na	431	36.45	8.15	4.48%	0.36	-	-	128.03	-	128.03
CCCT Wet "F", 2x1	4250	56%	22.57	na	431	28.76	2.87	6.27%	0.18	-	-	54.38	-	54.38
CCCT Wet "F", DF, 2x1	4250	16%	40.27	na	431	34.09	0.32	0.00%	0.00	-	-	74.68	-	74.68
CCCT Dry "F", 1x1	5050	56%	26.15	na	431	29.41	2.57	7.50%	0.19	-	-	58.33	-	58.33
CCCT Dry "F", DF, 1x1	5050	16%	44.44	na	431	36.75	0.08	0.00%	0.00	-	-	81.27	-	81.27
CCCT Dry "F", 2x1	5050	56%	23.20	na	431	29.07	2.42	7.67%	0.19	-	-	54.87	-	54.87
CCCT Dry "F", DF, 2x1	5050	16%	42.98	na	431	36.60	0.08	0.00%	0.00	-	-	79.66	-	79.66
CCCT Dry "G/H", 1x1	5050	56%	23.89	na	431	29.63	2.94	6.99%	0.21	-	-	56.66	-	56.66
CCCT Dry "G/H", DF, 1x1	5050	16%	47.70	na	431	35.65	0.08	0.00%	0.00	-	-	83.43	-	83.43
CCCT Dry "G/H", 2x1	5050	56%	22.43	na	431	29.10	2.82	7.27%	0.21	-	-	54.55	-	54.55
CCCT Dry "G/H", DF, 2x1	5050	16%	46.80	na	431	34.97	0.07	0.00%	0.00	-	-	81.84	-	81.84
CCCT Dry "J", Adv 1x1	5050	56%	22.45	na	431	28.02	2.54	6.98%	0.18	-	-	53.19	-	53.19
CCCT Dry "J", DF, Adv 1x1	5050	16%	41.22	na	431	37.15	0.08	0.00%	0.00	-	-	78.45	-	78.45

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, $0 CO2 Tax (Continued)

$0 CO2 Tax		Capital Cost $/kW			Fixed Cost					
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
Intercooled SCCT Aero x1	6500	$1,189	8.428%	$100.24	17.91	1.40%	0.25	17.07	35.24	$135.47
SCCT Frame "F" x1	6500	$804	7.954%	$63.91	9.13	1.37%	0.13	19.16	28.42	$92.33
IC Recips x6	6500	$1,469	8.428%	$123.84	19.03	0.40%	0.08	16.27	35.37	$159.21
CCCT Dry "G/H", 2x1	6500	$1,159	7.886%	$91.40	6.80	1.86%	0.13	12.99	19.91	$111.31
CCCT Dry "G/H", DF, 2x1	6500	$600	7.886%	$47.32	0.00	0.00%	0.00	15.61	15.61	$62.93
CCCT Dry "J", Adv 1x1	6500	$1,110	7.886%	$87.54	10.88	1.95%	0.21	12.51	23.60	$111.14
CCCT Dry "J", DF, Adv 1x1	6500	$486	7.886%	$38.36	0.00	0.00%	0.00	16.58	16.58	$54.94
IGCC with CCS	6500	$5,931	7.438%	$441.13	60.76	0.00%	0.00	0.00	60.76	$501.90
Generic Geothermal PPA 90% CF	4500	$0	6.831%	$0.00	735.46	0.00%	0.00	0.00	735.46	$735.46
2.3 MW turbine 29% CF WA	1500	$2,365	8.165%	$193.12	33.11	1.14%	0.38	0.00	33.49	$226.61
2.3 MW turbine 29% CF UT	4500	$2,304	8.165%	$188.12	33.11	1.14%	0.38	0.00	33.49	$221.61
2.3 MW turbine 40% CF WY	6500	$2,257	8.165%	$184.30	33.11	1.14%	0.38	0.00	33.49	$217.78
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	$3,153	8.165%	$257.48	51.50	2.45%	1.26	0.00	52.76	$310.24
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	$2,952	8.165%	$241.05	27.81	2.45%	0.68	0.00	28.49	$269.54
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	$3,176	8.165%	$259.29	32.55	2.45%	0.80	0.00	33.35	$292.64
Forestry Byproduct	1500	$3,334	7.542%	$251.45	40.65	5.07%	2.06	0.00	42.71	$294.16
Pumped Storage	4500	$3,000	7.459%	$223.77	4.30	6.19%	0.27	0.00	4.57	$228.34
Sodium-Sulfur Battery	4500	$4,400	8.722%	$383.77	27.40	0.00%	0.00	0.00	27.40	$411.17
Advanced Fly Wheel	4500	$2,406	8.722%	$209.85	96.24	0.00%	0.00	0.00	96.24	$306.09
CAES	4500	$1,751	8.428%	$147.57	33.80	0.00%	0.00	21.95	55.75	$203.33
Advanced Fission	4500	$7,093	7.623%	$540.70	88.75	5.79%	5.14	0.00	93.89	$634.59

Table 6.2 – Total Resource Cost for Supply-Side Resource Options, $0 CO2 Tax (Continued)

$0 CO2 Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
Intercooled SCCT Aero x1	6500	21%	73.64	na	431	38.26	3.39	6.83%	0.23	-	-	115.52	-	115.52
SCCT Frame "F" x1	6500	21%	50.19	na	431	42.93	10.00	7.80%	0.78	-	-	103.90	-	103.90
IC Recips x6	6500	21%	86.55	na	431	36.45	8.60	4.48%	0.39	-	-	131.98	-	131.98
CCCT Dry "G/H", 2x1	6500	56%	22.69	na	431	29.10	2.92	7.27%	0.21	-	-	54.92	-	54.92
CCCT Dry "G/H", DF, 2x1	6500	16%	44.90	na	431	34.97	0.07	0.00%	0.00	-	-	79.94	-	79.94
CCCT Dry "J", Adv 1x1	6500	56%	22.66	na	431	28.02	2.62	6.96%	0.18	-	-	53.48	-	53.48
CCCT Dry "J", DF, Adv 1x1	6500	16%	39.20	na	431	37.15	0.08	0.00%	0.00	-	-	76.43	-	76.43
IGCC with CCS	6500	86%	66.96	na	271	29.91	13.52	12.08%	1.63	-	-	112.02	-	112.02
Generic Geothermal PPA 90% CF	4500	90%	93.28	na	-	-	11.00	0.00%	0.00	-	-	104.29	-	104.29
2.3 MW turbine 29% CF WA	1500	29%	89.20	na	-	-	0.00	0.00%	0.00	2.55	-	91.76	(19.48)	72.28
2.3 MW turbine 29% CF UT	4500	29%	87.23	na	-	-	0.00	0.00%	0.00	2.55	-	89.79	(19.48)	70.31
2.3 MW turbine 40% CF WY	6500	40%	62.15	na	-	-	0.65	0.00%	0.00	2.55	-	65.36	(19.48)	45.88
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	22%	160.98	na	-	-	0.00	0.00%	0.00	0.64	-	161.62	(19.91)	141.70
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	28%	108.69	na	-	-	0.00	0.00%	0.00	0.64	-	109.33	(14.49)	94.84
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	34%	98.86	na	-	-	0.00	0.00%	0.00	0.64	-	99.50	(13.06)	86.45
Forestry Byproduct	1500	91%	37.00	na	512	51.29	0.96	0.00%	0.00	-	-	89.25	(17.86)	71.39
Pumped Storage	4500	42%	62.56	77.5%	472	59.32	4.30	0.00%	0.00	-	-	126.18	-	126.18
Sodium-Sulfur Battery	4500	25%	187.75	72.5%	472	63.41	0.00	0.00%	0.00	-	-	251.16	-	251.16
Advanced Fly Wheel	4500	5%	698.84	85.0%	472	54.09	0.00	0.00%	0.00	-	-	752.93	-	752.93
CAES	4500	33%	69.63	83.5%	472	55.06	22.51	10.29%	2.32	-	-	149.52	-	149.52
Advanced Fission	4500	86%	84.67	na	85	9.11	2.04	0.00%	0.00	-	-	95.82	-	95.82

Table 6.3 – Total Resource Cost for Supply-Side Resource Options, \$16 CO_2 Tax

$16 CO2 Tax		Capital Cost $/kW			Fixed Cost					
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3, ISO	0	$1,081	8.428%	$91.13	9.88	1.34%	0.13	32.51	42.52	$133.65
Intercooled SCCT Aero x1, ISO	0	$1,004	8.428%	$84.61	15.23	1.40%	0.21	29.59	45.04	$129.65
SCCT Frame "F" x1, ISO	0	$679	7.954%	$53.98	7.73	1.37%	0.11	33.21	41.05	$95.02
IC Recips x6, ISO	0	$1,204	8.428%	$101.45	15.61	0.40%	0.06	28.19	43.87	$145.31
CCCT Dry "F", 2x1, ISO	0	$995	7.886%	$78.43	6.13	1.23%	0.08	22.49	28.69	$107.12
CCCT Dry "F", DF, 2x1, ISO	0	$522	7.886%	$41.13	0.00	0.00%	0.00	28.31	28.31	$69.44
CCCT Dry "G/H", 1x1, ISO	0	$971	7.886%	$76.59	10.70	1.96%	0.21	22.92	33.83	$110.42
CCCT Dry "G/H", DF, 1x1, ISO	0	$612	7.886%	$48.23	0.00	0.00%	0.00	27.58	27.58	$75.81
CCCT Dry "G/H", 2x1, ISO	0	$959	7.886%	$75.63	5.61	1.86%	0.10	22.51	28.22	$103.85
CCCT Dry "G/H", DF, 2x1, ISO	0	$600	7.886%	$47.32	0.00	0.00%	0.00	27.05	27.05	$74.37
CCCT Dry "J", Adv 1x1, ISO	0	$931	7.886%	$73.39	9.13	1.95%	0.18	21.68	30.98	$104.37
CCCT Dry "J", DF, Adv 1x1, ISO	0	$486	7.886%	$38.36	0.00	0.00%	0.00	28.74	28.74	$67.10
Intercooled SCCT Aero x1	1500	$1,034	8.428%	$87.12	15.67	1.40%	0.22	29.50	45.39	$132.51
SCCT Frame "F" x1	1500	$699	7.954%	$55.56	7.97	1.37%	0.11	33.21	41.29	$96.85
IC Recips x 6	1500	$1,253	8.428%	$105.64	16.31	0.40%	0.06	28.19	44.57	$150.21
CCCT Dry "F", 2x1	1500	$1,039	7.886%	$81.97	6.43	1.23%	0.08	22.49	29.00	$110.96
CCCT Dry "F", DF, 2x1	1500	$522	7.886%	$41.13	0.00	0.00%	0.00	28.31	28.31	$69.44
CCCT Dry "G/H", 2x1	1500	$1,000	7.886%	$78.87	5.86	1.86%	0.11	22.61	28.57	$107.45
CCCT Dry "G/H", DF, 2x1	1500	$600	7.886%	$47.32	0.00	0.00%	0.00	27.15	27.15	$74.47
CCCT Dry "J", Adv 1x1	1500	$962	7.886%	$75.83	9.43	1.95%	0.18	21.68	31.29	$107.13
CCCT Dry "J", DF, Adv 1x1	1500	$486	7.886%	$38.36	0.00	0.00%	0.00	28.74	28.74	$67.10
SCCT Aero x3	4250	$1,225	8.428%	$103.21	11.11	1.34%	0.15	21.95	33.21	$136.42
Intercooled SCCT Aero x1	4250	$1,127	8.428%	$94.97	16.97	1.40%	0.24	19.99	37.19	$132.16
SCCT Frame "F" x1	4250	$762	7.954%	$60.57	8.67	1.37%	0.12	22.43	31.22	$91.79
IC Recips x6	4250	$1,368	8.428%	$115.31	18.39	0.40%	0.07	19.04	37.50	$152.82
CCCT Wet "F", 2x1	4250	$1,104	7.886%	$87.05	8.58	0.70%	0.06	15.03	23.67	$110.71
CCCT Wet "F", DF, 2x1	4250	$490	7.886%	$38.63	0.00	0.00%	0.00	17.81	17.81	$56.44
CCCT Dry "F", 1x1	5050	$1,253	7.886%	$98.81	13.94	1.29%	0.18	15.36	29.49	$128.29
CCCT Dry "F", DF, 1x1	5050	$546	7.886%	$43.08	0.00	0.00%	0.00	19.20	19.20	$62.28
CCCT Dry "F", 2x1	5050	$1,159	7.886%	$91.37	7.14	1.23%	0.09	15.19	22.42	$113.79
CCCT Dry "F", DF, 2x1	5050	$522	7.886%	$41.13	0.00	0.00%	0.00	19.12	19.12	$60.25
CCCT Dry "G/H", 1x1	5050	$1,129	7.886%	$89.04	12.45	1.96%	0.24	15.48	28.17	$117.21
CCCT Dry "G/H", DF, 1x1	5050	$612	7.886%	$48.23	0.00	0.00%	0.00	18.62	18.62	$66.86
CCCT Dry "G/H", 2x1	5050	$1,118	7.886%	$88.16	6.55	1.86%	0.12	15.20	21.87	$110.03
CCCT Dry "G/H", DF, 2x1	5050	$600	7.886%	$47.32	0.00	0.00%	0.00	18.27	18.27	$65.59
CCCT Dry "J", Adv 1x1	5050	$1,075	7.886%	$84.74	10.54	1.95%	0.21	14.64	25.39	$110.13
CCCT Dry "J", DF, Adv 1x1	5050	$486	7.886%	$38.36	0.00	0.00%	0.00	19.41	19.41	$57.77
Intercooled SCCT Aero x1	6500	$1,189	8.428%	$100.24	17.91	1.40%	0.25	17.07	35.24	$135.47
SCCT Frame "F" x1	6500	$804	7.954%	$63.91	9.13	1.37%	0.13	19.16	28.42	$92.33
IC Recips x6	6500	$1,469	8.428%	$123.84	19.03	0.40%	0.08	16.27	35.37	$159.21
CCCT Dry "G/H", 2x1	6500	$1,159	7.886%	$91.40	6.80	1.86%	0.13	12.99	19.91	$111.31
CCCT Dry "G/H", DF, 2x1	6500	$600	7.886%	$47.32	0.00	0.00%	0.00	15.61	15.61	$62.93
CCCT Dry "J", Adv 1x1	6500	$1,110	7.886%	$87.54	10.88	1.95%	0.21	12.51	23.60	$111.14
CCCT Dry "J", DF, Adv 1x1	6500	$486	7.886%	$38.36	0.00	0.00%	0.00	16.58	16.58	$54.94

Table 6.3 – Total Resource Cost for Supply-Side Resource Options, \$16 CO_2 Tax (Continued)

$16 CO2 Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
SCCT Aero x3, ISO	0	21%	72.65	na	498	48.47	3.50	6.67%	0.23	-	3.86	128.72	-	128.72
Intercooled SCCT Aero x1, ISO	0	21%	70.48	na	498	44.13	2.92	6.83%	0.20	-	3.52	121.24	-	121.24
SCCT Frame "F" x1, ISO	0	21%	51.65	na	498	49.52	8.46	7.80%	0.66	-	3.95	114.24	-	114.24
IC Recips x6, ISO	0	21%	78.99	na	498	42.04	7.40	4.33%	0.32	-	3.35	132.10	-	132.10
CCCT Dry "F", 2x1, ISO	0	56%	21.84	na	498	33.53	2.11	7.69%	0.16	-	2.67	60.31	-	60.31
CCCT Dry "F", DF, 2x1, ISO	0	16%	49.54	na	498	42.21	0.08	0.00%	0.00	-	3.36	95.19	-	95.19
CCCT Dry "G/H", 1x1, ISO	0	56%	22.51	na	498	34.17	2.53	7.05%	0.18	-	2.72	62.12	-	62.12
CCCT Dry "G/H", DF, 1x1, ISO	0	16%	54.09	na	498	41.12	0.08	0.00%	0.00	-	3.28	98.56	-	98.56
CCCT Dry "G/H", 2x1, ISO	0	56%	21.17	na	498	33.56	2.44	7.30%	0.18	-	2.67	60.02	-	60.02
CCCT Dry "G/H", DF, 2x1, ISO	0	16%	53.06	na	498	40.34	0.07	0.00%	0.00	-	3.21	96.69	-	96.69
CCCT Dry "J", Adv 1x1, ISO	0	56%	21.28	na	498	32.32	2.20	7.03%	0.15	-	2.58	58.53	-	58.53
CCCT Dry "J", DF, Adv 1x1, ISO	0	16%	47.87	na	498	42.86	0.08	0.00%	0.00	-	3.41	94.22	-	94.22
Intercooled SCCT Aero x1	1500	21%	72.03	na	498	43.99	2.99	6.83%	0.20	-	3.51	122.73	-	122.73
SCCT Frame "F" x1	1500	21%	52.65	na	498	49.52	8.71	7.80%	0.68	-	3.95	115.50	-	115.50
IC Recips x 6	1500	21%	81.65	na	498	42.04	7.63	4.48%	0.34	-	3.35	135.02	-	135.02
CCCT Dry "F", 2x1	1500	56%	22.62	na	498	33.53	2.18	7.67%	0.17	-	2.67	61.17	-	61.17
CCCT Dry "F", DF, 2x1	1500	16%	49.54	na	498	42.21	0.08	0.00%	0.00	-	3.36	95.20	-	95.20
CCCT Dry "G/H", 2x1	1500	56%	21.90	na	498	33.71	2.54	7.29%	0.19	-	2.69	61.02	-	61.02
CCCT Dry "G/H", DF, 2x1	1500	16%	53.13	na	498	40.49	0.07	0.00%	0.00	-	3.23	96.92	-	96.92
CCCT Dry "J", Adv 1x1	1500	56%	21.84	na	498	32.32	2.27	7.01%	0.16	-	2.58	59.17	-	59.17
CCCT Dry "J", DF, Adv 1x1	1500	16%	47.87	na	498	42.86	0.08	0.00%	0.00	-	3.41	94.22	-	94.22
SCCT Aero x3	4250	21%	74.16	na	472	45.97	3.89	6.67%	0.26	-	3.86	128.15	-	128.15
Intercooled SCCT Aero x1	4250	21%	71.84	na	472	41.85	3.23	6.83%	0.22	-	3.52	120.66	-	120.66
SCCT Frame "F" x1	4250	21%	49.90	na	472	46.97	9.48	7.80%	0.74	-	3.95	111.03	-	111.03
IC Recips x6	4250	21%	83.07	na	472	39.87	8.15	4.48%	0.36	-	3.35	134.81	-	134.81
CCCT Wet "F", 2x1	4250	56%	22.57	na	472	31.46	2.87	6.27%	0.18	-	2.64	59.73	-	59.73
CCCT Wet "F", DF, 2x1	4250	16%	40.27	na	472	37.30	0.32	0.00%	0.00	-	3.13	81.02	-	81.02
CCCT Dry "F", 1x1	5050	56%	26.15	na	472	32.17	2.57	7.50%	0.19	-	2.70	63.79	-	63.79
CCCT Dry "F", DF, 1x1	5050	16%	44.44	na	472	40.21	0.08	0.00%	0.00	-	3.38	88.10	-	88.10
CCCT Dry "F", 2x1	5050	56%	23.20	na	472	31.80	2.42	7.67%	0.19	-	2.67	60.27	-	60.27
CCCT Dry "F", DF, 2x1	5050	16%	42.98	na	472	40.04	0.08	0.00%	0.00	-	3.36	86.46	-	86.46
CCCT Dry "G/H", 1x1	5050	56%	23.89	na	472	32.41	2.94	6.99%	0.21	-	2.72	62.17	-	62.17
CCCT Dry "G/H", DF, 1x1	5050	16%	47.70	na	472	39.00	0.08	0.00%	0.00	-	3.28	90.05	-	90.05
CCCT Dry "G/H", 2x1	5050	56%	22.43	na	472	31.83	2.82	7.27%	0.21	-	2.67	59.96	-	59.96
CCCT Dry "G/H", DF, 2x1	5050	16%	46.80	na	472	38.26	0.07	0.00%	0.00	-	3.21	88.34	-	88.34
CCCT Dry "J", Adv 1x1	5050	56%	22.45	na	472	30.66	2.54	6.98%	0.18	-	2.58	58.40	-	58.40
CCCT Dry "J", DF, Adv 1x1	5050	16%	41.22	na	472	40.65	0.08	0.00%	0.00	-	3.41	85.36	-	85.36
Intercooled SCCT Aero x1	6500	21%	73.64	na	472	41.85	3.39	6.83%	0.23	-	3.52	122.63	-	122.63
SCCT Frame "F" x1	6500	21%	50.19	na	472	46.97	10.00	7.80%	0.78	-	3.95	111.88	-	111.88
IC Recips x6	6500	21%	86.55	na	472	39.87	8.60	4.48%	0.39	-	3.35	138.76	-	138.76
CCCT Dry "G/H", 2x1	6500	56%	22.69	na	472	31.83	2.92	7.27%	0.21	-	2.67	60.33	-	60.33
CCCT Dry "G/H", DF, 2x1	6500	16%	44.90	na	472	38.26	0.07	0.00%	0.00	-	3.21	86.44	-	86.44
CCCT Dry "J", Adv 1x1	6500	56%	22.66	na	472	30.66	2.62	6.96%	0.18	-	2.58	58.69	-	58.69
CCCT Dry "J", DF, Adv 1x1	6500	16%	39.20	na	472	40.65	0.08	0.00%	0.00	-	3.41	83.34	-	83.34

Table 6.3 – Total Resource Cost for Supply-Side Resource Options, \$16 CO_2 Tax (Continued)

$16 CO2 Tax		Capital Cost $/kW			Fixed Cost					
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
IGCC with CCS	6500	$5,931	7.438%	$441.13	60.76	0.00%	0.00	0.00	60.76	$501.90
Generic Geothermal PPA 90% CF	4500	$0	6.831%	$0.00	735.46	0.00%	0.00	0.00	735.46	$735.46
2.3 MW turbine 29% CF WA	1500	$2,365	8.165%	$193.12	33.11	1.14%	0.38	0.00	33.49	$226.61
2.3 MW turbine 29% CF UT	4500	$2,304	8.165%	$188.12	33.11	1.14%	0.38	0.00	33.49	$221.61
2.3 MW turbine 40% CF WY	6500	$2,257	8.165%	$184.30	33.11	1.14%	0.38	0.00	33.49	$217.78
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	$3,153	8.165%	$257.48	51.50	2.45%	1.26	0.00	52.76	$310.24
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	$2,952	8.165%	$241.05	27.81	2.45%	0.68	0.00	28.49	$269.54
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	$3,176	8.165%	$259.29	32.55	2.45%	0.80	0.00	33.35	$292.64
Forestry Byproduct	1500	$3,334	7.542%	$251.45	40.65	5.07%	2.06	0.00	42.71	$294.16
Pumped Storage	4500	$3,000	7.459%	$223.77	4.30	6.19%	0.27	0.00	4.57	$228.34
Sodium-Sulfur Battery	4500	$4,400	8.722%	$383.77	27.40	0.00%	0.00	0.00	27.40	$411.17
Advanced Fly Wheel	4500	$2,406	8.722%	$209.85	96.24	0.00%	0.00	0.00	96.24	$306.09
CAES	4500	$1,751	8.428%	$147.57	33.80	0.00%	0.00	21.95	55.75	$203.33
Advanced Fission	4500	$7,093	7.623%	$540.70	88.75	5.79%	5.14	0.00	93.89	$634.59

$16 CO2 Tax		Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
Supply Side Resource Options Mid-Calendar Year 2012 Dollars ($)					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	¢/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
IGCC with CCS	6500	86%	66.96	na	271	29.91	13.52	12.08%	1.63	-	0.76	112.79	-	112.79
Generic Geothermal PPA 90% CF	4500	90%	93.28	na	-	-	11.00	0.00%	0.00	-	-	104.29	-	104.29
2.3 MW turbine 29% CF WA	1500	29%	89.20	na	-	-	0.00	0.00%	0.00	2.55	-	91.76	(19.48)	72.28
2.3 MW turbine 29% CF UT	4500	29%	87.23	na	-	-	0.00	0.00%	0.00	2.55	-	89.79	(19.48)	70.31
2.3 MW turbine 40% CF WY	6500	40%	62.15	na	-	-	0.65	0.00%	0.00	2.55	-	65.36	(19.48)	45.88
PV Poly-Si Fixed Tilt 22% CF (1.21 MWdc/MWac)	4500	22%	160.98	na	-	-	0.00	0.00%	0.00	0.64	-	161.62	(19.91)	141.70
PV Poly-Si Fixed Tilt 28% CF (1.37 MWdc/MWac)	4500	28%	108.69	na	-	-	0.00	0.00%	0.00	0.64	-	109.33	(14.49)	94.84
PV Poly-Si Single Tracking 34% CF (1.34 MWdc/MWac)	4500	34%	98.86	na	-	-	0.00	0.00%	0.00	0.64	-	99.50	(13.06)	86.45
Forestry Byproduct	1500	91%	37.00	na	512	51.29	0.96	0.00%	0.00	-	6.90	96.15	(17.86)	78.29
Pumped Storage	4500	42%	62.56	77.5%	472	59.32	4.30	0.00%	0.00	-	-	126.18	-	126.18
Sodium-Sulfur Battery	4500	25%	187.75	72.5%	472	63.41	0.00	0.00%	0.00	-	-	251.16	-	251.16
Advanced Fly Wheel	4500	5%	698.84	85.0%	472	54.09	0.00	0.00%	0.00	-	-	752.93	-	752.93
CAES	4500	33%	69.63	83.5%	472	55.06	22.51	10.29%	2.32	-	3.86	153.38	-	153.38
Advanced Fission	4500	86%	84.67	na	85	9.11	2.04	0.00%	0.00	-	-	95.82	-	95.82

Table 6.4- Glossary of Terms from Supply Side Resource Table

Term	**Description**
Fuel:	Primary fuel used for electricity generation or storage.
Resource:	Primary technology used for electricity generation or storage.
Elevation (afsl):	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW):	Net dependable capacity is the net electrical output for a given technology at the given elevation and annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year:	First year the resource could be placed in service; available for generation and dispatch.
Design Life (yrs):	Average number of years the resource is expected to be "used and useful", based on various factors such as OEM guarantees, fuel availability and environmental regulations.
Base Capital ($/kW):	Total capital expenditure in $/kW for the development and construction of a resource, including direct costs (equipment, buildings, installation/overnight construction, commissioning, EPC fees/profit, and contingency), owner's costs (land acquisition, water rights, air permitting, rights of way, design engineering, spare parts, project management costs, legal/financial costs, grid interconnection costs, owner's contingency), and financial costs (AFUDC, capital surcharge, property taxes, escalation).)
Var O&M ($/MWh):	Includes real levelized variable operating costs such as combustion turbine maintenance, raw water costs, boiler water/circulating water treatment chemicals, pollution control chemicals, equipment maintenance chemicals, and fired hour fee.
Fixed O&M ($/KW-yr):	Includes fixed operating costs: labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, training.
Full Load Heat Rate HHV (Btu/KWh):	Efficiency of a resource to generate electricity for a given heat input in a "new and clean" condition.
EFOR (%):	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates, for a given resource at the given site.
POR (%):	Estimated Planned Outage Rate for a given resource at the given site.
Water Consumed (gal/MWh):	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO_2 (lbs/MMBtu):	Expected permitted level of sulfur dioxide emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu):	Expected permitted level of nitrogen oxides (expressed as NO_2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu):	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO2 (lbs/MMBtu):	Pounds of carbon dioxide emitted per million Btu of heat input.

Table 6.5 – Glossary of Acronyms Used in the Supply Side Resource Table

Acronyms	Description
Adv:	Advanced (Combined Cycle Combustion Turbine)
AFSL:	Average Feet (Above) Sea Level
CAES:	Compressed Air Energy Storage
CCCT:	Combined Cycle Combustion Turbine
CCS:	Carbon Capture and Sequestration
CF:	Capacity Factor
CSP:	Concentrated Solar Power
DF:	Duct Firing
IC:	Internal Combustion
IGCC:	Integrated Gasification Combined Cycle
ISO:	International Organization for Standardization (Temp = 59 F/15 C, Pressure = 14.7 psia/1.013 bar)
PC CCS:	Pulverized Coal-Carbon Capture and Sequestration
PV Poly-Si:	Photovoltaic cells constructed from poly-crystalline silicon semiconductor wafers
Recip:	Reciprocating Engine
SCCT:	Simple Cycle Combustion Turbine
SCPC:	Super-Critical Pulverized Coal
SO:	Solid Oxide (Fuel Cell)

Some important factors that apply to the Supply Side Resource Tables are listed below:

- Capital costs are all-inclusive and include Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Table 6.5 reflect mid-2012 dollars, and do not include escalation from mid-year to the year of commercial operation.
- Costs of energy for solar resources include investment tax credits. Hybrid solar with natural gas backup would not qualify for investment tax credits.
- Wind, hydrokinetic, biomass, and geothermal resources are assumed to qualify for Production Tax Credits (PTC), depending on the installation date.
- Capital costs include interconnection costs to the transmission system (switchyard and other upgrades needed to interconnect the resource to PacifiCorp's transmission network) but do not include transmission system network upgrades.
- For the nuclear resource, capital costs include the cost of storing spent fuel on-site during the life of the facility. Costs for ultimate off-site disposal of spent fuel are not included.
- Wind resources are representative generic resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources are identified as part of the acquisition process. An estimate for wind integration costs, \$2.55/MWh, has been added to variable O&M cost.
- State specific tax benefits are excluded from the IRP supply side table but would be considered in the evaluation of a specific project.

A sensitivity analysis was prepared for three Natural Gas-fired Combined Cycle Combustion Turbine resource options at varying capacity factors. Table 6.6 shows the total resource cost results for this analysis.

Table 6.6 – Total Resource Cost, Natural Gas-fired plants at varying Capacity Factors (2012$)

Total Resource Cost (Mills/kWh)				
Capacity Factor CCCT	**Elevation**	**40%**	**56%**	**80%**
Capacity Factor Duct Fire	**(AFSL)**	**10%**	**16%**	**22%**
CCCT Wet "F", 2x1	4250	$68.75	$59.73	$52.96
CCCT Wet "F", DF, 2x1	4250	$105.18	$81.02	$70.04
CCCT Dry "F", 1x1	5050	$74.25	$63.79	$55.95
CCCT Dry "F", DF, 1x1	5050	$114.76	$88.10	$75.98
CCCT Dry "F", 2x1	5050	$69.55	$60.27	$53.32
CCCT Dry "F", DF, 2x1	5050	$112.25	$86.46	$74.74
CCCT Dry "G/H", 1x1	5050	$71.73	$62.17	$55.00
CCCT Dry "G/H", DF, 1x1	5050	$118.67	$90.05	$77.04
CCCT Dry "G/H", 2x1	5050	$68.93	$59.96	$53.23
CCCT Dry "G/H", DF, 2x1	5050	$116.42	$88.34	$75.58
CCCT Dry "J", Adv 1x1	5050	$67.38	$58.40	$51.66
CCCT Dry "J", DF, Adv 1x1	5050	$110.09	$85.36	$74.12

Distributed Generation

Table 6.7 presents cost and performance attributes for small combined heart and power and solar resource options.

Tables 6.8 and 6.9 present the total resource cost attributes for small combined heat and power and solar resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2012 dollars. The resource costs are presented for both the $0 and $16 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs. Additional explanatory notes for the tables are as follows:

- Administrative costs, representing the estimated cost of delivering a program to end-use customers, are included for solar photovoltaic and water heating systems. Small combined heart and power are considered qualifying facilities as such do not include administrative or interconnection costs.
- As available, federal tax benefits are included for the following resources based on a percent of capital cost.
    - Reciprocating Engine 10 percent
    - Microturbine 10 percent
    - Fuel Cell 30 percent
    - Gas Turbine 10 percent
    - Industrial Biomass 10 percent
    - Anaerobic Digesters 10 percent
- The resource cost for Industrial Biomass is based on data from The Cadmus Group, Inc. (Cadmus). The fuel is assumed to be provided by the project owner at no cost, a conservative assumption. In reality, the cost to the Company would be each state's filed avoided cost rate.
- Installation costs for on-site ("micro") solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. If available, capital costs are adjusted downward to reflect federal tax credits of 30 percent of installed system costs. Conversely, no adjustment is made for state tax incentives as these are not included in the Total Resource Cost test that sees the incentive as a benefit to customers but also as a cost to the state's tax payers, making the net effect zero. In Utah, these resources are assessed on a Utility Cost Test basis, considering only utility incentives and program administrative

Table 6.7- Distributed Generation Resource Supply-Side Options

	Location / Timing		Plant Details				Outage Information		Costs			Emissions			
Supply-side Resource Options Mid-Calendar Year 2012 Dollars ($) **Resource Description**	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW	Fuel	Design Plant Life in Years	Annual Average Heat Rate HHV BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
Small Combined Heat & Power															
Reciprocating Engine	Idaho	2013	0.40	Natural Gas	20	8,000	2%	3%	$ 1,495	-	$ 47.41	0.001	0.101	0.255	118.00
Reciprocating Engine	Utah	2013	6.61	Natural Gas	20	8,000	2%	3%	$ 1,495	-	$ 47.41	0.001	0.101	0.255	118.00
Reciprocating Engine	Oregon / California	2013	1.04	Natural Gas	20	8,000	2%	3%	$ 1,495	-	$ 47.41	0.001	0.101	0.255	118.00
Reciprocating Engine	Washington	2013	1.28	Natural Gas	20	8,000	2%	3%	$ 1,495	-	$ 47.41	0.001	0.101	0.255	118.00
Reciprocating Engine	Wyoming	2013	0.89	Natural Gas	20	8,000	2%	3%	$ 1,495	-	$ 47.41	0.001	0.101	0.255	118.00
Gas Turbine	Idaho	2013	0.14	Natural Gas	20	6,300	2%	3%	$ 1,757	-	$ 55.42	0.001	0.050	0.255	118.00
Gas Turbine	Utah	2013	1.90	Natural Gas	20	6,300	2%	3%	$ 1,757	-	$ 55.42	0.001	0.050	0.255	118.00
Gas Turbine	Oregon	2013	0.27	Natural Gas	20	6,300	2%	3%	$ 1,757	-	$ 55.42	0.001	0.050	0.255	118.00
Gas Turbine	Washington	2013	0.13	Natural Gas	20	6,300	2%	3%	$ 1,757	-	$ 55.42	0.001	0.050	0.255	118.00
Gas Turbine	Wyoming	2013	0.30	Natural Gas	20	6,300	2%	3%	$ 1,757	-	$ 55.42	0.001	0.050	0.255	118.00
Microturbine	Utah	2013	0.95	Natural Gas	10	8,000	2%	3%	$ 2,168	-	$ 63.42	0.001	0.101	0.255	118.00
Fuel Cell	Utah	2013	0.47	Natural Gas	10	6,100	2%	3%	$ 3,673	-	$ 186.91	0.001	0.003	0.255	118.00
Commercial Biomass, Anaerobic Digester	Utah	2013	0.20	Biomass	25	-	10%	10%	$ 2,452	-	$ 61.78	-	-	-	-
Commercial Biomass, Anaerobic Digester	Wyoming	2013	0.16	Biomass	25	-	10%	10%	$ 2,452	-	$ 61.78	-	-	-	-
Industrial Biomass, Waste	Utah	2013	0.16	Biomass	25	-	5%	5%	$ 631	-	$ 28.82	-	-	-	-
Industrial Biomass, Waste	Oregon / California	2013	0.55	Biomass	25	-	5%	5%	$ 631	-	$ 28.82	-	-	-	-
Solar															
Rooftop Photovoltaic (Utility Cost)	Utah	2013	13.116	Solar	30	-			$ 902	-	-	-	-	-	-
Rooftop Photovoltaic	Wyoming	2013	0.291	Solar	30	-			$ 4,693	-	$ 20.47	-	-	-	-
Rooftop Photovoltaic	Oregon / California	2013	7.613	Solar	30	-			$ 4,753	-	$ 20.47	-	-	-	-
Rooftop Photovoltaic	Idaho	2013	0.148	Solar	30	-			$ 4,693	-	$ 20.47	-	-	-	-
Rooftop Photovoltaic	Washington	2013	0.154	Solar	30	-			$ 4,693	-	$ 20.47	-	-	-	-
Water Heaters (Utility Cost)	Utah	2013	1.531	Solar	20	-			$ 194	-	-	-	-	-	-
Water Heaters	Oregon	2013	2.159	Solar	20	-			$ 1,600	-	$ 20.36	-	-	-	-

Table 6.8 – Distributed Generation Total Resource Cost, \$0 CO_2 Tax

\$0 CO2 Tax		Capital Cost \$/kW					Fixed Cost		Convert to Mills		Levelized Fuel		Variable Costs (mills/kWh)					
Supply-side Resource Options Mid-Calendar Year 2012 Dollars (\$) Resource Description	Location	Tax Incentive	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation	Environmental	**Total Resource Cost with Tax Benefits (Mills/kWh)**	Tax Incentive (Mills/kWh)	**Total Resource Cost without Tax Benefits (Mills/kWh)**
Small Combined Heat & Power																		
Reciprocating Engine	Idaho	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	431.47	34.52	-	\$ 2.06	-	\$ 95.39	\$ 5.03	\$ 100.42
Reciprocating Engine	Utah	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	431.47	34.52	-	\$ 2.06	-	\$ 95.39	\$ 5.03	\$ 100.42
Reciprocating Engine	Oregon / California	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 3.05	-	\$ 99.62	\$ 5.03	\$ 104.65
Reciprocating Engine	Washington	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	472.04	37.76	-	\$ 3.05	-	\$ 99.62	\$ 5.03	\$ 104.65
Reciprocating Engine	Wyoming	\$ 166		\$ 1,495	10.61%	\$ 158.65	\$ 47.41	\$ 206.07	40%	58.81	431.47	34.52	-	\$ 1.76	-	\$ 95.09	\$ 5.03	\$ 100.12
Gas Turbine	Idaho	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	431.47	27.18	-	\$ 1.62	-	\$ 62.89	\$ 2.92	\$ 65.81
Gas Turbine	Utah	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	-	\$ 65.45	\$ 2.92	\$ 68.37
Gas Turbine	Oregon	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	472.04	29.74	-	\$ 1.62	-	\$ 65.45	\$ 2.92	\$ 68.37
Gas Turbine	Washington	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	431.47	27.18	-	\$ 1.62	-	\$ 62.89	\$ 2.92	\$ 65.81
Gas Turbine	Wyoming	\$ 195		\$ 1,757	10.61%	\$ 186.45	\$ 55.42	\$ 241.87	81%	34.09	431.47	27.18	-	\$ 1.62	-	\$ 62.89	\$ 2.92	\$ 65.81
Microturbine	Utah	\$ 241		\$ 2,168	14.39%	\$ 311.92	\$ 63.42	\$ 375.34	49%	87.44	431.47	34.52	-	\$ 2.06	-	\$ 124.02	\$ 8.07	\$ 132.09
Fuel Cell	Utah	\$ 1,574		\$ 3,673	14.39%	\$ 528.51	\$ 186.91	\$ 715.42	71%	115.03	431.47	26.32	-	\$ 1.57	-	\$ 142.92	\$ 36.42	\$ 179.33
Commercial Biomass, Anaerobic Digester	Utah	\$ 272		\$ 2,452	8.17%	\$ 200.23	\$ 61.78	\$ 262.00	46%	65.09	-	-	-	-	-	\$ 65.09	\$ 5.53	\$ 70.62
Commercial Biomass, Anaerobic Digester	Wyoming	\$ 272		\$ 2,452	8.17%	\$ 200.23	\$ 61.78	\$ 262.00	46%	65.09	-	-	-	-	-	\$ 65.09	\$ 5.53	\$ 70.62
Industrial Biomass, Waste	Utah	\$ 70		\$ 631	8.17%	\$ 51.50	\$ 28.82	\$ 80.32	90%	10.19	-	-	-	-	-	\$ 10.19	\$ 0.73	\$ 10.91
Industrial Biomass, Waste	Oregon / California	\$ 70		\$ 631	8.17%	\$ 51.50	\$ 28.82	\$ 80.32	90%	10.19	-	-	-	-	-	\$ 10.19	\$ 0.73	\$ 10.91
Solar																		
Rooftop Photovoltaic (Utility Cost)	Utah		\$ 902	\$ 902	7.54%	\$ 68.05	-	\$ 68.05	17%	45.70	-	-	-	-	-	\$ 45.70	-	\$ 45.70
Rooftop Photovoltaic	Wyoming	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	19%	229.23	-	-	-	-	-	\$ 229.23	\$ 92.87	\$ 322.11
Rooftop Photovoltaic	Oregon / California	\$ 2,037	\$ 133	\$ 4,753	7.54%	\$ 358.49	\$ 20.47	\$ 378.96	16%	274.87	-	-	-	-	-	\$ 274.87	\$ 111.44	\$ 386.31
Rooftop Photovoltaic	Idaho	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	15%	279.35	-	-	-	-	-	\$ 279.35	\$ 113.17	\$ 392.52
Rooftop Photovoltaic	Washington	\$ 2,011	\$ 131	\$ 4,693	7.54%	\$ 353.93	\$ 20.47	\$ 374.40	14%	298.88	-	-	-	-	-	\$ 298.88	\$ 121.09	\$ 419.97
Water Heaters (Utility Cost)	Utah		\$ 194	\$ 194	9.15%	\$ 17.72	-	\$ 17.72	6%	33.92	-	-	-	-	-	\$ 33.92	-	\$ 33.92
Water Heaters	Oregon	\$ 752	\$ 267	\$ 1,600	9.15%	\$ 146.45	\$ 20.36	\$ 166.81	7%	263.15	-	-	-	-	-	\$ 263.15	\$ 108.58	\$ 371.73

Table 6.9 – Distributed Generation Total Resource Cost, $16 CO_2 Tax

$16 CO2 Tax		Capital Cost $/kW					Fixed Cost		Convert to Mills		Levelized Fuel		Variable Costs (mills/kWh)					
Supply-side Resource Options Mid-Calendar Year 2012 Dollars ($) **Resource Description**	Location	Tax Incentive	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Environmental	**Total Resource Cost (Mills/kWh)**	Tax Incentive (Mills/kWh)	**Total Resource Cost without Tax Benefits (Mills/kWh)**
Small Combined Heat & Power																		
Reciprocating Engine	Idaho	$ 166		$ 1,495	10.61%	$ 158.65	$ 47.41	$ 206.07	40%	58.81	472.04	37.76	-	$ 2.06	3.17	$ 101.80	$ 5.03	$ 106.83
Reciprocating Engine	Utah	$ 166		$ 1,495	10.61%	$ 158.65	$ 47.41	$ 206.07	40%	58.81	472.04	37.76	-	$ 2.06	3.17	$ 101.80	$ 5.03	$ 106.83
Reciprocating Engine	Oregon / California	$ 166		$ 1,495	10.61%	$ 158.65	$ 47.41	$ 206.07	40%	58.81	497.71	39.82	-	$ 3.05	3.17	$ 104.85	$ 5.03	$ 109.88
Reciprocating Engine	Washington	$ 166		$ 1,495	10.61%	$ 158.65	$ 47.41	$ 206.07	40%	58.81	497.71	39.82	-	$ 3.05	3.17	$ 104.85	$ 5.03	$ 109.88
Reciprocating Engine	Wyoming	$ 166		$ 1,495	10.61%	$ 158.65	$ 47.41	$ 206.07	40%	58.81	472.04	37.76	-	$ 1.76	3.17	$ 101.50	$ 5.03	$ 106.53
Gas Turbine	Idaho	$ 195		$ 1,757	10.61%	$ 186.45	$ 55.42	$ 241.87	81%	34.09	472.04	29.74	-	$ 1.62	2.50	$ 67.94	$ 2.92	$ 70.86
Gas Turbine	Utah	$ 195		$ 1,757	10.61%	$ 186.45	$ 55.42	$ 241.87	81%	34.09	497.71	31.36	-	$ 1.62	2.50	$ 69.56	$ 2.92	$ 72.48
Gas Turbine	Oregon	$ 195		$ 1,757	10.61%	$ 186.45	$ 55.42	$ 241.87	81%	34.09	497.71	31.36	-	$ 1.62	2.50	$ 69.56	$ 2.92	$ 72.48
Gas Turbine	Washington	$ 195		$ 1,757	10.61%	$ 186.45	$ 55.42	$ 241.87	81%	34.09	472.04	29.74	-	$ 1.62	2.50	$ 67.94	$ 2.92	$ 70.86
Gas Turbine	Wyoming	$ 195		$ 1,757	10.61%	$ 186.45	$ 55.42	$ 241.87	81%	34.09	472.04	29.74	-	$ 1.62	2.50	$ 67.94	$ 2.92	$ 70.86
Microturbine	Utah	$ 241		$ 2,168	14.39%	$ 311.92	$ 63.42	$ 375.34	49%	87.44	472.04	37.76	-	$ 2.06	3.17	$ 130.44	$ 8.07	$ 138.51
Fuel Cell	Utah	$ 1,574		$ 3,673	14.39%	$ 528.51	$ 186.91	$ 715.42	71%	115.03	472.04	28.79	-	$ 1.57	2.42	$ 147.81	$ 36.42	$ 184.23
Commercial Biomass, Anaerobic Digester	Utah	$ 272		$ 2,452	8.17%	$ 200.23	$ 61.78	$ 262.00	46%	65.09	-	-	-	-	-	$ 65.09	$ 5.53	$ 70.62
Commercial Biomass, Anaerobic Digester	Wyoming	$ 272		$ 2,452	8.17%	$ 200.23	$ 61.78	$ 262.00	46%	65.09	-	-	-	-	-	$ 65.09	$ 5.53	$ 70.62
Industrial Biomass, Waste	Utah	$ 70		$ 631	8.17%	$ 51.50	$ 28.82	$ 80.32	90%	10.19	-	-	-	-	-	$ 10.19	$ 0.73	$ 10.91
Industrial Biomass, Waste	Oregon / California	$ 70		$ 631	8.17%	$ 51.50	$ 28.82	$ 80.32	90%	10.19	-	-	-	-	-	$ 10.19	$ 0.73	$ 10.91
Solar																		
Rooftop Photovoltaic (Utility Cost)	Utah		$ 902	$ 902	7.54%	$ 68.05	-	$ 68.05	17%	45.70	-	-	-	-	-	$ 45.70	-	$ 45.70
Rooftop Photovoltaic	Wyoming	$ 2,011	$ 131	$ 4,693	7.54%	$ 353.93	$ 20.47	$ 374.40	19%	229.23	-	-	-	-	-	$ 229.23	$ 92.87	$ 322.11
Rooftop Photovoltaic	Oregon / California	$ 2,037	$ 133	$ 4,753	7.54%	$ 358.49	$ 20.47	$ 378.96	16%	274.87	-	-	-	-	-	$ 274.87	$ 111.44	$ 386.31
Rooftop Photovoltaic	Idaho	$ 2,011	$ 131	$ 4,693	7.54%	$ 353.93	$ 20.47	$ 374.40	15%	279.35	-	-	-	-	-	$ 279.35	$ 113.17	$ 392.52
Rooftop Photovoltaic	Washington	$ 2,011	$ 131	$ 4,693	7.54%	$ 353.93	$ 20.47	$ 374.40	14%	298.88	-	-	-	-	-	$ 298.88	$ 121.09	$ 419.97
Water Heaters (Utility Cost)	Utah		$ 194	$ 194	9.15%	$ 17.72	-	$ 17.72	6%	33.92	-	-	-	-	-	$ 33.92	-	$ 33.92
Water Heaters	Oregon	$ 752	$ 267	$ 1,600	9.15%	$ 146.45	$ 20.36	$ 166.81	7%	263.15	-	-	-	-	-	$ 263.15	$ 108.58	$ 371.73

Resource Option Description

Coal

Potential coal resources are shown in the supply-side resource options table as supercritical pulverized coal boilers (PC) and IGCC, located in both Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have increased by approximately 50 to 60 percent due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. Current economic conditions have mitigated many of these concerns and changes in price for coal generation have been relatively stable since the previous IRP. The uncertainty of both proposed and future carbon regulations and difficulty in obtaining environmental permits for coal based generation requires the Company to postpone the selection of coal as a resource before 2020.

Supercritical technology was chosen over subcritical technology for pulverized coal for a number of reasons. Increasing coal costs are making the added efficiency of the supercritical technology cost-effective. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission intensity rates are smaller than for similarly sized subcritical units. Compared to subcritical boilers, supercritical boilers have better load following capability, faster ramp rates, use less water and require less steel for construction. The smaller steel requirements have also leveled the construction cost estimates for the two coal technologies. The costs for a supercritical PC facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multi-unit plant at a new site versus the cost of a single unit addition at an existing site.

The potential requirement for CO_2 capture and sequestration (CCS) represents a significant cost for new and, possibly, existing coal resources. Currently proposed federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) regulations would require CCS for new coal units to meet the proposed emissions limit. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from pulverized coal boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would store the CO_2 underground for long-term storage and monitoring.

PacifiCorp continues to monitor CO_2 capture technologies for possible retrofit application on its existing coal-fired resources, as well as their applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO_2 removal becomes necessary in the future. An option to capture CO_2 at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a limited number of large-scale sequestration projects in operation around the world; most of these have been installed in conjunction with enhanced oil recovery. CCS is not considered a viable option before 2025 due to risk issues associated with the availability of commercial sequestration sites and the uncertainty regarding long term liabilities for underground sequestration.

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal, with amine-based carbon capture, is the reduced cost of capturing CO_2 from the process. Only a limited number of IGCC plants have been built and operated around the world.

In the United States, these facilities have been demonstration projects, resulting in capital and operating costs that are significantly greater than those costs for conventional coal plants. The majority of these projects have been constructed with significant funding from the federal government. Two large, utility-scale IGCC plants are currently in construction: Duke Energy's Edwardsport Plant that utilizes General Electric's gasification technology and Southern Company's Kemper County plant that utilizes Southern Company's Transport Integrated Gasifier (TRIG). A third IGCC project, utilizing Siemens gasification technology, the Texas Clean Energy Project, is currently in an advanced stage of development. The costs presented in the supply-side resource options tables reflect 2007 studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants, which are manifested as lower plant heat rates, are realized by: (1) continuous operations improvement, (2) monitoring the quality of the fuel supply, and (3) upgrading components if economically justified. Efficiency improvements can result in a smaller emissions footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units, primarily measured by the heat rate (the ratio of heat input to energy output) degrades gradually as components wear over time. During operation, controllable process parameters are adjusted to optimize the unit's power output compared to its heat input. Typical overhaul work that contributes to improved efficiency includes (1) major equipment overhauls of the steam generating equipment and combustion/steam turbine generators, (2) overhauls of the cooling systems and (3) overhauls of the pollution control equipment.

When economically justified, efficiency improvements are obtained through major component upgrades of the electricity generating equipment. The most notable examples of upgrades resulting in greater generating capacity are steam turbine upgrades and generator upgrades. Turbine upgrades consist of adding additional rows of blades to the rearward section of the turbine shaft (generically known as a "dense pack" configuration), but can also include replacing existing blades, replacing end seals and enhancing seal packing media. Generator upgrades consist of cleaning and rewinding the coils in the stator, and servicing the electromagnetic core. Such upgrade opportunities are analyzed on a case-by-case basis, and are tied to a unit's major overhaul cycle, and, because they are often capital intensive, are only implemented if economically justified.

Natural Gas

A number of natural gas fueled generation options are included in the supply-side resource options table and are intended to represent technologies that are both currently commercially available and/or will be available over the next few years. Both simple and combined cycle configurations are included. Capital costs for gas-fueled generation options approximate capital costs reported in previous IRPs. In real terms, capital costs have shown a modest decline compared to the 2011 IRP, primarily driven by limited domestic orders for new gas-fired generation due to a lack of current economic growth.

Combustion turbine options include both simple and combined cycle configurations. The simple cycle (SCCT) options include traditional frame machines as well as aero-derivative combustion turbines. Two aero-derivative options are included: the General Electric LM6000PG combustion turbine and General Electric's LMS100. These machines are flexible, high efficiency machines and can be installed with high temperature oxidation catalysts for carbon monoxide (CO) control and an SCR system for nitrogen oxides (NOx) control, which allows them to be located in areas with air emissions concerns. LM6000 gas turbines have quick-start capability (less than ten minutes to full load) and higher heating value net full load heat rates near 10,000 Btu/kWh. For the current supply side resource table, the GE LM6000PG machine was selected, which has a slightly higher output than the LM6000PC machine used in the previous IRP supply side resource table and which are installed at the Company's Gadsby Plant. As in the previous IRP, the supply-side resource table includes General Electric's LMS100 intercooled gas turbine. This combustion turbine has been successful since its debut with 28 units in service with approximately another 20 being installed as of summer 2012. It is a cross between a simple-cycle aero-derivative gas turbine and a frame machine with compressor inter-cooling to improve efficiency. The machines have higher heating value net full load heat rates of less than 9,000 Btu/kWh and similar starting capabilities as the LM6000 with significant load following capability (up to 50 MW per minute).

Frame simple cycle machines are represented by the "F" class technology and in the case of the current IRP Supply Side Resource options table the frame machine reflects a General Electric 7F 5 series (previously referred to as the 7FA.05). One combustion turbine can generate approximately 180 MW at Western U.S. elevations; they have efficiencies similar to the LM6000 family of combustion turbines when operating in simple cycle.

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of six machines at 17.2 MW each at Western elevations. The underlying technology for this category is the Wartsila 18V50SG engine; these machines are spark-ignited and have the advantages of a relatively low (when compared to simple cycle combustion turbines), low emissions profile, and a high level of availability and reliability due to the relatively high number of machines for a given target capacity block. They are capable of being brought on line up to full load in less than ten minutes and have excellent part-load efficiency which is again due to fact that there is a high number of machines for a given capacity. These types of engines also have the advantage of being relatively insensitive to elevation and do not require high-pressure natural gas, which is typical of advanced combustion turbines. In previous IRPs, the underlying technology was the Wartsila 20V34SG, a smaller engine.

At present, fuel cells hold less promise for large utility scale applications due to high capital and maintenance costs, partly attributable to the lack of production capability and limited development. Fuel cell applications are beginning to advance in small scale with some customers.

A number of combined cycle configurations have been provided in this version of the Supply Side Resource options table. Configuration options include 1x1 and 2x1 configurations based on "F" and "G/H" combustion turbines. The "G/H" frame combustion turbine, although they are supplied by different equipment manufacturers, are combined, since the power and performance outputs are relatively similar. Also included in the current version of the Supply Side Resource options table is the new “J” class combustion turbine, which is a large advanced combustion turbine (approximately 470 megawatts in a 1x1 combined cycle configuration under ISO conditions). The “J” class combustion turbine is now commercially available in the United States, though no orders have been placed to date. The Supply Side Resource table also includes Duct Firing (“DF”), which is not a stand-alone resource option, but is considered to be an available option for any combined cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency and also a mechanism to recover lost power generation capability due to high ambient temperatures. The amount of duct firing in the supply side resource options table are stated as fixed values at 50 MW for the 1x1 configuration and 100 MW for the 2x1 configuration, though in reality the amount of duct firing is a design consideration which means the incremental capacity that can be added is flexible. In most cases, all combined cycle options listed in the current supply side resource table are based on dry cooling (i.e. using an air cooled condenser) , rather than wet cooling (i.e. using a forced draft cooling tower). It is assumed that the availability of water in the western United States will continue to be limited. Furthermore, during cold weather cooling towers can have plumes that are sometimes considered a visual nuisance. The assumption of dry cooling is considered to be both prudent and conservative. In certain cases and sites, sufficient water may be available for wet cooling, in which case, performance and efficiency would be improved; the overall costs of energy would be site-specific depending on the total cost of water (commodity cost, transport/storage infrastructure cost, treatment cost, discharge cost) .

Wind

Resource Supply, Location, and Incremental Transmission Costs

It should be noted that the primary drivers of wind resource selection are the requirements of renewable portfolio standards and the availability of production tax credits. In the previous IRP, incremental transmission costs were expressed as dollars-per-kW values that were applied to costs of wind resources added in wind-generation-only bubbles. In the present IRP, the availability of certain wind resources is contingent upon the different Energy Gateway transmission scenarios. In the Energy Gateway scenario 1, no new Wyoming wind is available. The availability of higher capacity factor, lower cost Wyoming wind increases moving from Energy Gateway scenarios 2 through 5. In Energy Gateway scenarios 1, 2, and 4 the only available wind resource on the west side of the system delivers energy to the Willamette Valley bubble and assumes a BPA wheel from McNary to the Willamette Valley (inclusive of BPA wind integration charges). It is assumed that any potential capital required by BPA is included in the cost of the wheel. This west side wind resource further assumes an incremental PacifiCorp Transmission capital cost of $10 million (2012$), which equates to $33.33/kW (2012$). For Energy Gateway scenarios 3 and 5, a wind resource is available, which delivers energy to the Northwest via the transmission path Windstar to Hemmingway. This resource reflects additions in Gorge vial route through Boardman and then to Bethel. No BPA wheeling costs apply. No incremental transmission costs will be assigned to this resource (assumes Energy Gateway Segment H costs cover all transmission integration requirements). Table 6.10 below shows the total cumulative wind selection limits for each wind resource based upon Energy Gateway scenario.

Table 6.10 – Cumulative Wind Selection Limits by Year and Energy Gateway Scenario

Wind Resource	Capacity Factor	Total MW Available 2016	2017	2018	2019	2020	2021	>2021	Energy Gateway Scenario
Wyoming (Aeolius)	40%	-	-	-	-	-	-	-	EG1
Wyoming (Aeolius)	40%	-	-	-	650	650	650	650	EG2
Wyoming (Aeolius)	40%	-	-	-	650	1,200	1,200	1,200	EG3
Wyoming (Aeolius)	40%	-	-	-	650	650	1,000	1,000	EG4
Wyoming (Aeolius)	40%	-	-	-	650	650	1,500	1,500	EG5
Oregon/ Washington (Willamette Valley)	29%	-	-	-	300	300	300	300	EG 1,2,4
Oregon/ Washington (Bethel)	29%	-	-	-	600	600	600	600	EG 3,5
South Utah Wind	29%	-	200	200	200	200	200	200	All EG 1-5
Idaho (Goshen) Wind	29%	-	600	600	600	600	600	600	All EG 1-5

Capital Costs

Capital cost estimates for wind projects are based on the development and construction costs of previously built projects and 2012 market prices for the wind turbine generators. All wind resources are specified in 100 MW blocks, but the model can choose a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Wyoming resource options are assigned a capacity factor value of40 percent, while wind resources in other states are assigned a value of 29 percent. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk models. The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $2.55/MWh (in 2012 dollars) for resource selection. The source of this value was the Company's 2012 wind integration study, which is included as Appendix H. Integration costs were incorporated into wind capital costs based on a 25-year project life expectancy and generation performance.

Other Renewable Resources

Other renewable generation resources included in the supply-side resource options table include geothermal, biomass and solar.

Geothermal

The 2010 IRP Update included information from a 2010 geothermal study (see Table 6.11) that was commissioned by PacifiCorp and performed by Black & Veatch[43]. The 2010 study focused on geothermal projects that could demonstrate commercial viability and were in advanced phases of development.

[43] The 2010 geothermal study is available on PacifiCorp's IRP web page. http://www.pacificorp.com/es/irp.html.

Table 6.11 – 2010 Geothermal Study Results

Table 1-1. Sites Selected for In-Depth Review.							
Field Name	**State**	**Additional Capacity Available (Gross MW)**	**Additional Capacity Available (Net MW)**	**Additional Capacity Available to PacifiCorp (Net MW)[a]**	**Anticipated Plant Type for Additonal Capacity**	**LCOE (Low, $/MWh)[b,c]**	**LCOE (High, $/MWh)[b,c]**
Lake City	CA	30	24	24	Binary	$83	$90
Medicine Lake	CA	480	384	384	Binary	$91	$98
Raft River	ID	90	72	43	Binary	$93	$100
Neal Hot Springs	OR	30	24	0	Binary	$80	$87
Cove Fort	UT	100	80	60 to 63	Binary	$68	$75
Crystal-Madsen	UT	30	24	0	Binary	$93	$100
Roosevelt Hot Springs	UT	90	81[d]	81[d]	Flash/Binary Hybrid	$46	$51
Thermo Hot Springs	UT	118	94	0	Binary	$91	$98
Totals		***968***	***783***	***592 to 595***			

Source: BVG analysis for PacifiCorp.
Note:
[a] Calculated by subtracting the amount of resource under contract to or in contract negotiations with other parties from the estimated net capacity available.
[b] Net basis
[c] These screening level cost estimates are based on available public information. More detailed estimates based on proprietary information and calculated on a consistent basis might yield different comparisons.
[d] While 81 MW net are estimated to be available, the resource should be developed in smaller increments to verify resource sustainability

In response to the 2010 IRP Update, comments from stakeholders requested additional information on geothermal projects near PacifiCorp's service territory that are in the early stages of exploration and development. PacifiCorp issued a Geothermal Information Request (GIR) to the public in 2011 to identify geothermal projects in the early stages of exploration and development. Black & Veatch was commissioned to review the responses, categorize the development stage of each project and recommend projects to PacifiCorp. As a result of the GIR, PacifiCorp received Information on 16 projects in the early stages of development from 10 respondents.

Black & Veatch reviewed the information provided and evaluated each of the 16 projects. The projects were categorized according to the Geothermal Energy Association's definition of the four phases of energy development:

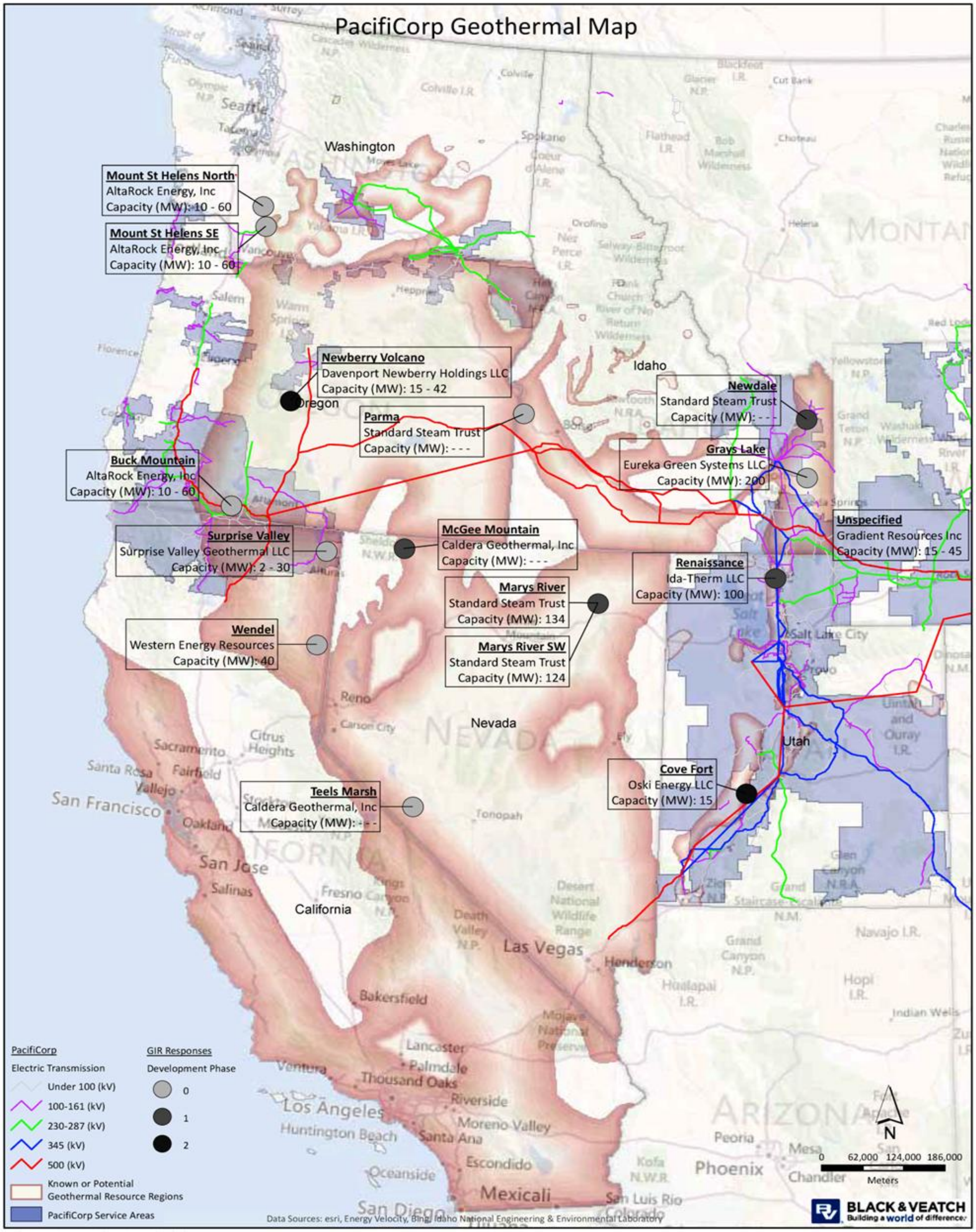
- Phase 1 – Resource Procurement and Identification
- Phase 2 – Resource Exploration and Confirmation
- Phase 3 – Permitting and Initial Development
- Phase 4 – Resource Production and Power Plant Construction

Projects that did not meet the minimum requirements to be labeled phase 1 were categorized as phase 0. All 16 projects were categorized as phase 0, phase 1, or phase 2. Black & Veatch reviewed the experience of the project team, viability of the site, generation technology, economics, readiness and system interconnection of each project and recommended six projects. The six projects are shown below in Table 6.12 and Figure 6.3. The six recommended projects include two projects from each phase of development represented. Two of the recommended projects plan to use Enhanced Geothermal Systems (EGS), a technology that has not been commercially applied in the United States. The remaining four projects plan to use binary technology, which is inherently more costly and less efficient than the flash design suitable for projects with higher-temperature brine. The equivalent energy cost for each of the six projects ranges between \$100 and \$180/MWh. All six projects are in early stages of development and will have higher development risks than projects that have successfully completed higher phases of development.

Table 6.12 – 2012 Geothermal Study Results

PHASE	DEVELOPER	PROJECT	LOCATION	MW	TYPE
2	Oski Energy	Cove Fort	Cove Fort, UT	15	Binary (Kalina)
	Davenport Newberry	Newberry Volcano	Deschutes County, OR	15	Likely Binary /Flash EGS
1	Standard Steam Trust	Newdale	Newdale, ID	Undef.	Binary
	Ida-Therm	Renaissance	Honeyville, UT	100	Binary
0	AltaRock Energy	Buck Mountain	Klamath Falls, OR	10	Dual Flash EGS
	Surprise Valley	Surprise Valley Hot Springs	Modoc County, CA	2-5	Binary

Figure 6.3 - Commercially Viable Geothermal Resources near PacifiCorp's Service Territory



The cost recovery mechanisms currently available to PacifiCorp as a public electric utility are not compatible with the inherent risks associated with the development of geothermal resources for the production of electricity. The primary risks of geothermal development are dry holes, insufficient temperature and insufficient pressure. These risks cannot be quantified until after wells are dug. The costs to confirm production capability of a geothermal energy resource can be as high as 35 percent of total project development costs. Test wells drilled during the exploration phase of project development are typically estimated to cost between $500,000 and $1.5 million per well. Full diameter wells drilled during the confirmation phase of development are estimated to cost between $4 million and $5 million per well. Variations in the permeability of subsurface materials can determine whether wells in close proximity are commercially viable, lacking in pressure or temperature, or completely dry with no interconnectivity to a geothermal resource. As a regulated utility subject to the public utility commissions of six states, PacifiCorp is not compensated nor incentivized to engage in risk inherent activities.

To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include all development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the Company and its customers. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be “used and useful,” obtaining a mechanism to recover geothermal development costs may be difficult.

Biomass

Cost and performance data for biomass based resources were obtained from third-party studies. In general, large-scale (greater than 50 MW) plants are rare, which is why the resource option shows a 5 MW plant on the supply side resource table. Nonetheless, select coal plants have been converted from burning coal to burning various types of biomass, including wood chips, cellulosic switch grass, municipal solid waste, or, in rare cases, an engineered fuel which adds processing and sorbents to the aforementioned base fuels. Certain coal plants have been identified as candidates for coal to biomass conversion, most notably Portland General Electric’s 580 MW Boardman Plant in Oregon. The greatest challenge to building large biomass plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The transport and handling logistics of large quantities of biomass fuel poses a significant challenge, depending on the size of the facility. Because of the need to be close to a large source of biomass, the Pacific Northwest or Atlantic Southeast are generally considered good regions for siting biomass resources. The climate and economy of these regions promotes growth of trees in large plantations. While PacifiCorp currently does not own any biomass plants, the company does purchase power from a number of biomass fueled installations in Oregon through power purchase agreements.

Solar

Three solar technologies are included in the supply side resource table: photovoltaic (PV) crystalline (both fixed and single axis tracking) and concentrated solar. Market prices for PV crystalline solar panels have dropped substantially during the past five plus years, giving the PV crystalline technology a cost advantage over concentrated solar and thin film. Unlike other resource options, the real capital costs for PV solar resources have been projected to decline slightly over the IRP study period. To model these decreases in real capital cost, data from PacifiCorp's 2012 market estimate and the price change curve of the nominalized 2009 NREL price forecast data were used.

Oregon passed a law in 2009 that requires electric utilities in the state to meet photovoltaic solar generation requirements with facilities in Oregon that have nameplate capacities between 500 kW and 5 MW. PacifiCorp is required to have a total of 8.7 MW of photovoltaic solar sources within its generation system in Oregon by January 1, 2020.

To meet the Oregon solar requirement, PacifiCorp issued an RFP for solar projects and commissioned a study to evaluate solar resources in 2011. The Black Cap solar facility was selected in the RFP process and was constructed in 2012. The Black Cap facility represents completion of 2 MW of PacifiCorp's 8.7 MW solar requirement in Oregon. A study to evaluate solar resources in Oregon was completed by Black & Veatch and focused on development of 2 MW projects that could be built to meet Oregon's solar generation requirement. The Oregon report evaluated PV thin film, fixed tilt PV multi-crystalline, and single axis PV multi-crystalline installations. Capital cost information in the Oregon report was updated in August 2012 to incorporate market changes in the cost of equipment. Information from this report is the basis for cost and production data for 2 MW solar resources listed in the Supply Side Resource table.

In August 2012, PacifiCorp commissioned an additional cost and performance evaluation on estimated energy production, capital and operating and maintenance costs for a nominal 50 MW solar PV resource located in southwestern Utah. The Utah estimate studied fixed-tilt and single-axis mounting systems for PV crystalline solar panels. The higher annual insolation and solar irradiance in Utah improved capacity factors and economy of scale benefits of the 50 MW resource compared to the 2 MW resource, resulting in lower total energy costs.

Distributed Supply Side Resources

As in the previous IRP, three general categories of small-scale customer-sited generation (also referred to as Distributed Generation) were included as resource options in the 2013 IRP; Combined Heat and Power (CHP), Solar Photovoltaics ("Solar PV") and Solar Water Heating ("SWH"). Traditionally, such resources fall outside the standard classification of Class 2 DSM resources for two main reasons: either they reduce utility-provided electricity consumption at the building level (rather than at an end-use level, as applies to CHP and PV), or they rely on renewable resources (solar PV, SWH, and certain CHP technologies).

CHP systems generate electricity and utilize waste heat for thermal loads, such as space or water heating. They can be used in buildings with a fairly coincident thermal and electric load, or in buildings producing combustible biomass or biogas, such as lumber mills or landfills. CHP broadly divides into subcategories based on fuels used: nonrenewable CHP typically runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

The IRP includes the same CHP systems as in the 2011 IRP:

- Nonrenewable
  - Reciprocating engines (RE);
  - Microturbines (MT);
  - Gas turbines (GT); and
  - Fuel cells (FC).
- Renewable
  - Industrial biomass systems are utilized in industries such as lumber mills or pulp and paper manufacturing, where site-generated waste products can be combusted in place of natural gas or other fuels.
  - Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste.

Solar PV systems include a collection of solar modules, generally mounted on building roofs, with an inverter to convert available sunlight into electricity compatible with a building's standard electrical infrastructure. Widely applicable in the residential and nonresidential sectors, Solar PV has been in use for several decades. In 2012, the Utah Public Service Commission approved a large expansion of the Utah Solar Incentive Program. The program is designed to encourage the development of distributed Solar PV through the payment of a rebate to customers that complete the installation of onsite Solar PV generation facilities. Based on utility experience with similar incentive programs, the 2013 IRP assumes that the program will have full participation and drive the installation of 60 MW of Solar PV resources across the Company's Utah service territory between 2013 and 2017. This has the impact of accelerating the adoption of Solar PV in Utah over the first five years of the 2013 IRP and if realized reduces the remaining potential in Utah in the later years of the plan.

SWH systems use sunlight to pre-heat domestic hot water tanks, reducing the need for electricity to heat water. Widely applicable in the residential and nonresidential sectors, SWHs have been in use for several decades.

Table 6.13 shows modeling attributes for the distributed generation resources reflected in "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in March 2013 by Cadmus ("DSM potential study").

Table 6.13 – Distributed Generation Resource Attributes[44]

	Available MW Capacity each Year by Topology Bubble 1/							Annual Fixed O&M Costs	Measure Life (Yrs)	Heat Rate (Ave. Btu/kWh)	Admin Cost (% of total program cost)	Capital Cost ($/kW), Total	Technology Cost Change
Technology Type	California	Oregon	Walla Walla, WA	Yakima, WA	Goshen, ID	Utah	Wyoming						
Reciprocating Engine	0.15	0.89	0.36	0.92	0.40	6.61	0.89	47.41	20	8,000	0%	1,495	1%
MicroTurbine	-	-	-	-	-	0.95	-	63.42	10	8,000	0%	2,168	-1%
Fuel Cell	-	-	-	-	-	0.47	-	186.91	10	6,100	0%	3,673	-3%
Gas Turbine	-	0.27	-	0.13	0.14	1.90	0.30	55.42	20	6,300	0%	1,757	1%
Industrial Biomass	-	0.55	-	-	-	0.16	-	28.82	25	N/A	0%	631	1%
Anaerobic Digesters	-	-	-	-	-	0.20	0.16	61.78	18	N/A	0%	2,452	-1%
PV	0.49	7.12	-	0.15	0.15	13.12	0.29	20.47	30	N/A	10%	4,693	-2%
Solar Water Heaters	-	2.16	-	-	-	1.53	-	20.36	20	N/A	10%	1,600	2%

[44] More details on the distributed generation resources can be found in the DSM potentials study report available for download on PacifiCorp's demand-side management Web page, http://www.pacificorp.com/es/dsm.html.

Nuclear
Included in the supply side resource table is a larger 2,236 MW system, which reflects the current state-of-the-art advanced nuclear plant and is modeled after the Westinghouse AP1000 technology currently being installed by Southern Company at the Vogtle Generating Station in Georgia. It is assumed that this technology would be installed at the proposed Blue Castle site near Green River, Utah. Nuclear fuel cost is assumed at $2,770/kg in 2011 dollars but nuclear power is not considered a viable option in the PacifiCorp service territory before 2030 due to total capital cost uncertainty (including EPC and owner's costs), sociopolitical resistance, and regulatory obstacles.

Energy Storage
As in past IRPs, a number of energy storage technologies are included, such as compressed energy storage (CAES), pumped hydroelectric, and advanced batteries. There are a number of potential CAES sites—specifically solution-mined sites associated with natural gas storage in western Utah and southwest Wyoming—that could be developed in areas of existing gas transmission. CAES may be an attractive alternative for high elevation sites since the gas compression could compensate for the facility capacity derate affects associated with higher elevation.

Energy storage continues to be of interest since the variable nature of some conventional renewable generation alternatives could be enhanced if the energy produced could be stored. To model the storage options, PacifiCorp conducted an energy storage study with HDR in 2011[45].

Table 6.14 outlines the conclusions of the HDR study. The focus of this study was in defining the cost and performance characteristics of available storage technologies. The dry cell and Zinc Bromide (ZnBr) battery options were removed because these systems are similar to other options shown. Zinc-bromide batteries are similar to the VRB batteries, while the dry cells are similar to the Lithium-Ion (Li-Ion) batteries.

Table 6.14 –HDR Energy Storage Study Summary Cost and Capacity Results (2011$)

	Flywheel	Li-Ion	NaS	VRB	Pumped Storage	CAES
System Cost ($/kW and/or $/kWh)	$2,406 per kW	$1,100 (High Energy)	$4,000/kW	$644/kWh	$1,500-$3,000/kW	$1,400-$1,700/kW
Rated System Size (MW)	20	89 (High Energy)	1	1	1,000	500
Rated Capacity (hrs)	0.25	4 (High Energy)	7.2	1	8 to 10	8

Numerous examples of pumped hydro systems are included in the HDR study and a composite case is presented in the resource table representing both the large size capable with this technology (1,000 MW) but at the high end of the cost range to reflect the permitting difficulties present with this geologic intense generation option. O&M is presented in both variable and fixed components. A larger variable component has been used to mirror the different potential capacity factors available with this flexible resource.

[45] The 2011 energy storage study is available on PacifiCorp's IRP web page. http://www.pacificorp.com/es/irp.html.

CAES has been shown at the specific size case illustrated in the HDR study. A 557 net MW capacity case is shown in the resource table at the 6,000 foot elevation example. Capital costs include the solution mining component of the technology. O&M costs are broken out into fixed and variable components.

Battery energy storage is unique in that capital costs are defined in terms of energy storage capability and not necessarily in terms of how much energy can be delivered instantaneously. In order to properly compare different battery systems it is necessary to compare the battery systems on a common denominator basis. The common denominator basis is defined by the sodium-sulfur (NaS) battery and all systems were compared on storing 7.2 hours of energy as shown in Table 6.15. All O&M in Table 6.15 is assumed fixed for ease of comparison.

Table 6.15 –HDR Storage Study, Normalized Battery Cost Comparison (2011$)

Battery	$/kW - Capacity	$/kWh Energy Storage	Replace-ment – 10 yr life	$ Millions	kWh – Energy Storage	$/kWh for Energy Storage	$/kW – Capacity & Energy	O&M $/kW-yr
Li-Ion		$1,100	$1,100	$8.71	7,200	$1,210	$8,712	$27.4
NaS	$4,000		$4,000	$4.40	7,200	$0.611	$4,400	$27.4
Vanadium Redox **(VRB)**	$400	$644	$644	$5.53	7,200	$0.768	$5,530	$36.5

Notes to Table 6-15:

Capacity Factor equal to 3 hours per day – 6 months per year = 6.25%
Battery size normalized at 1 MW
Normalize energy storage capability to 7.2 hours equal to the standard NaS system

Demand-side Resources

Resource Options and Attributes

Source of Demand-side Management Resource Data

Demand-side management (DSM) resource opportunity estimates used in the development of the 2013 IRP were derived from the DSM potential study. The DSM potential study, conducted by Cadmus, provided a broad estimate of the size, type, location and cost of demand-side resources.[46] For the purpose of integrated resource planning, the demand-side resource information from the DSM potential study was converted into supply curves by type of DSM (e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM) for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves

Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources. Supply curves provide a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling

[46] The 2013 DSM potential study is available on PacifiCorp's demand-side management web page. http://www.pacificorp.com/es/dsm.html.

utilizing supply curves allows utilities to select least-cost resources (products and quantities) based on each resource's competitiveness against alternative resource options.

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to demand-side supply curves include:

- Resource quantities available in each year—either megawatts or megawatt-hours—recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year;
- Persistence of resource savings; for example, Class 2 DSM (energy-based) resource measure lives
- Seasonal availability and hours available (Classes 1 and 3 DSM capacity resources)
- The hourly shape of the resource (load shape of the Class 2 DSM energy resource); and
- Levelized resource costs (dollars per kilowatt per year for Classes 1 and 3 DSM capacity resources, or dollars per megawatt-hour over the resource's life for Class 2 DSM energy resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

Class 1 DSM Capacity Supply Curves
Supply curves were created for three distinct Class 1 DSM products:

1) Direct load control (DLC) of residential and small commercial central air conditioning and water heating;
2) Irrigation load curtailment; and
3) Commercial/industrial curtailment

The potentials and costs for each product were provided at the state level resulting in three products across six states or the development of eighteen Class 1 DSM supply curves for the 2013 IRP modeling process.

Class 1 DSM resource price differences between West and East control areas for similar resources were driven by resource differences in each market, such as irrigation pump size and hours of operation as well as product performance differences. For instance, residential air conditioning load control in the West is more expensive on a unitized or dollar per kilowatt-year basis due to climatic differences that result in a lower load impact per installed switch.

The assessment of potential for distributed standby generation[47] was combined with an assessment of commercial/industrial energy management system controls in the development of the resource opportunity and costs of the commercial/industrial curtailment product. The costs for this product are constant across all jurisdictions assuming a pay-for-performance delivery model.

Recognizing that some Class 1 and 3 DSM products compete for the management of the same customer end-use loads, and to avoid overstating available impacts, the supply curves accounted for interactions within and between Class 1 and Class 3 DSM resources. Resources were prioritized within each customer sector by the firmness of the resource and then by cost. The following are examples of the logic that was applied to account for these interactions:

- Participation in the Class 1 DSM DLC air conditioning and water heating programs or DLC irrigation programs would take precedence over participation in Class 3 DSM Time-of-Use (TOU) rates/programs. Customers already enrolled in the DLC air conditioning and water heating and DLC irrigation programs would not opt out to participate in the TOU programs.
- Participation in the Class 1 DSM commercial/industrial curtailment programs would take precedent over Class 3 DSM Demand Buyback and/or Critical Peak Pricing programs where load curtailment is offered.

Tables 6.16 and 6.17 show the summary level Class 1 DSM resource information, by control area, used in the development of the Class 1 DSM resource supply curves. Potential shown is incremental to the existing Class 1 DSM resources identified in Table 5.10. For existing program offerings, it is assumed the Company could begin acquiring incremental potential in 2013. For resources representing new product offerings, it is assumed the Company could begin acquiring

[47] In February 2010 the Environmental Protection Agency made the Reciprocating Internal Combustion Engines National Emission Standards for Hazardous Air Pollutants ruling. The ruling puts restrictions on the use of standby generation after May, 2014 unless the generators meet the rulings required emission standards.

potential in 2014, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 6.16 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential and Small Commercial Air Conditioning and Water Heating	Residential time-of-use	50 hours, average of 4 hours per event	Summer	42	$83 - $103	2014
Irrigation Direct Load Control	Irrigation time-of-use	50 hours, average of 4 hours per event	Summer	11	$61 - $64	2014
Commercial/Industrial Curtailment (includes distributed standby generation)	Demand buyback and Critical peak pricing	30 hours, average of 4 hours per event	Summer and Winter	64	$65	2014

Table 6.17 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential and Small Commercial Air Conditioning and Water Heating	Residential time-of-use	50 hours, average of 4 hours per event	Summer	31	$70 - $133	2013-2014
Irrigation Direct Load Control	Irrigation time-of-use	50 hours, average of 4 hours per event	Summer	1	$51 - $64	2013-2014
Commercial/Industrial Curtailment (includes distributed standby generation)	Demand buyback and Critical peak pricing	30 hours, average of 4 hours per event	Summer and Winter	125	$65	2014

A number of data conversions and resource attributes are required to configure the supply curves for use in the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in $/kW-month. The following are the primary model attributes required by the model:

- **The Capacity Planning Factor (CPF):** This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Classes 1 and 3 DSM programs, this parameter is set to 1 (100 percent)
- **Additional reserves:** This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.

- **Daily and annual energy limits:** These parameters, expressed in Gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.
- **Nameplate capacity (MW) and service life (years)**
- **Maximum Annual Units:** This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- **First year and month available / last year available**

Class 3 DSM Capacity Supply Curves

Supply curves were created for four discrete Class 3 DSM products, which are capacity-based resources like Class 1 DSM products:

1) Residential time-of-use rates;
2) Commercial critical peak pricing;
3) Commercial and industrial demand buyback; and
4) Voluntary irrigation time-of-use[48]

The potentials and costs for each product were provided at the state level resulting in four products across six states or the development of twenty-four Class 3 DSM supply curves for the 2013 IRP modeling process.

As discussed above with regard to Class 1 DSM resources, the potential for each Class 3 DSM product was adjusted for expected interactions with competing Class 1 and 3 DSM resource options.

Modest product price differences between west and east control areas were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in which it is offered regardless of quantity available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year.

Tables 6.18 and 6.19 show the summary level Class 3 DSM resource information, by control area, used in the development of the Class 3 DSM resource supply curves. Potential shown is incremental to the existing Class 3 DSM resources identified in Table 5.10. For existing program offerings, it is assumed the Company could begin acquiring incremental potential in 2013. For resources representing new product offerings, it is assumed the Company could begin acquiring potential in 2014, accounting for the time required for program design, regulatory approval, vendor selection, etc. System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs.

Table 6.18 – Class 3 DSM Program Attributes, West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential Time-of-Use	Residential A/C and Water	528 hours	Summer	3	$117 - $347	2013 - 2014

[48] The 2011 IRP included significantly more potential for irrigation load control driven by the assumption of mandatory participation.

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
	Heating DLC					
Commercial Critical Peak Pricing	C&I Curtailment, Demand Buyback	40 hours	Summer and Winter	0*	$9 - $96	2014
Commercial/Industrial Demand Buyback	C&I Curtailment, Critical Peak Pricing	50 hours	Summer and Winter	0*	$26	2014
Voluntary Irrigation Time-of-Use	Irrigation DLC	120 hours	Summer	5	$40 - $97	2013 - 2014

** Although standalone potential was identified in the DSM potential study, there is assumed to be no potential available after accounting for competition with other Class 1 and 3 DSM resources.*

Table 6.19 – Class 3 DSM Program Attributes, East Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential Time-of-Use	Residential A/C and Water Heating DLC	480/600 hours	Summer	8	$124 - $195	2013 - 2014
Commercial Critical Peak Pricing	C&I Curtailment, Demand Buyback	40 hours	Summer and Winter	0*	$9 - $38	2014
Commercial/Industrial Demand Buyback	C&I Curtailment, Critical Peak Pricing	50 hours	Summer and Winter	0*	$26	2014
Voluntary Irrigation Time-of-Use	Irrigation DLC	120 hours	Summer	0.2	$20 - $97	2013 - 2014

** Although standalone potential was identified in the DSM potential study, there is assumed to be no potential available after accounting for competition with other Class 1 and 3 DSM resources.*

Class 2 DSM, Energy Supply Curves

The 2013 IRP represents the third time the Company has utilized the DSM supply curve methodology in the evaluation and selection of Class 2 DSM resources. The 2013 DSM potential study provided the information to fully assess the potential contribution from Class 2 DSM resources over the IRP planning horizon and adjusted resource potentials and costs to account for changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, and state specific resource evaluation considerations (e.g., cost-effectiveness criteria). Class 2 DSM resource potential was assessed by state down to the individual measure and facility levels; e.g., specific appliances, motors, lighting configurations for residential buildings, small offices, etc. The 2013 DSM potential study provided Class 2 DSM resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[49]
- **Measure:**

[49] Oregon's Class 2 DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

- 131 residential measures
- 145 commercial measures
- 93 industrial measures
- Three irrigation measures
- Four street lighting measures

- **Facility type[50]:**
  - Six residential facility types
  - 24 commercial facility types
  - 14 industrial facility types
  - One irrigation facility type
  - Four street lighting types

The 2013 DSM potential study levelized total resource costs (including measure costs and a 20 percent adder for program administrative costs) over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Consistent with regulatory mandates, Utah Class 2 DSM resource costs were levelized using utility costs (incentive and non-incentive program costs) instead of total resource costs.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 7.2 million MWh.[51] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (achievable). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 5.7 million MWh. The achievable technical potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of Class 2 DSM resource information available, it was impractical to model the Class 2 DSM resource supply curves at this level of detail. The combination of measures by facility type and state generated over 19,000 separate permutations or distinct measures that could be modeled using the supply curve methodology.[52] To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs to reduce the number of combinations to a more manageable number. The granularity or range of measure costs in a particular bundle were narrowed in the development of the Class 2 DSM supply curves in the 2013 IRP relative to the 2011 IRP to address concerns regarding using too broad of

[50] Facility type includes such attributes as existing or new construction, single or multi-family, etc. Facility types are more fully described in the 2013 DSM potential study.

[51] The identified technical potential represents the cumulative impact of Class 2 DSM measure installations in the 20th year of the study period. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period.

[52] Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

measure costs within a bundle and its possible impact on the selection of bundled resources at or near the IRP model's economic selection point. The result was the creation of twenty-seven cost bundles; eighteen more than were developed for the 2011 IRP.

Bundle development began with the Class 2 DSM technical potential identified by the 2013 DSM potential study. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest's aggressive[53] regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and 72 percent of lost-opportunity (new construction or equipment upgrade on failure) could be achievable over the 20-year planning period. Over the planning period, the aggregate (both discretionary and lost opportunity) achievable technical potential is 79 percent of the technical potential.

Consistent with the 2011 IRP, the technical achievable potential for each measure by state is assigned a measure and market ramp rate, reflecting the relative state of technology and program state specific delivery infrastructure/maturity, respectively. New technologies and states with newer programs were assumed to take more time to ramp up than those with more extensive track records.

The Energy Trust of Oregon (ETO) applies achievability assumptions and ramp rates in a similar manner in its resource assessment. For a more detailed description of the methods used in PacifiCorp's 2013 DSM Potential Study and the ETO's resource assessment, see Appendix D in Volume II of this document. In contrast to the 2011 IRP, the ETO did not perform an economic pre-screening of measures in the development of the Oregon DSM supply curves allowing resource opportunities in Oregon to be economically screened in the IRP model in a comparable way as is done across PacifiCorp's other five states.

Twenty-seven cost bundles were available across six states (including Oregon), which equates to 189 Class 2 DSM supply curves. Table 6.20 shows the MWh potential for Class 2 DSM cost bundles, designated by ranges of $/MWh. Table 6.21 shows the associated bundle price after applying cost credits afforded to Class 2 DSM resources within the model. These cost credits include the following:

- A transmission and distribution investment deferral credit of $54/kW-year;
- Stochastic risk reduction credit of $7.05/MWh[54];
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[55]

[53] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

[54] PacifiCorp developed this credit by taking the difference between a comparison of deterministic PaR runs for the 2011 IRP preferred portfolio with and without DSM and a comparison of stochastic PaR runs for the 2011 IRP preferred portfolio with and without DSM and then dividing that difference by the MWh of DSM in the 2011 IRP preferred portfolio.

[55] The formula for calculating the $/MWh credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

The bundle price is the average levelized cost for the group of measures in the cost range, weighted by potential. In specifying the bundle cost breakpoints, narrower cost ranges were defined for the lower-cost resources to improve the cost accuracy for the bundles considered more likely to be selected by the System Optimizer model. The highest-cost bundles were specified with wider cost breakpoints that are more granular than the cost ranges used in the development of the 2011 IRP[56].

Table 6.20 – Class 2 DSM MWh Potential by Cost Bundle

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	12,499	47,610	386,701	1,158,187	149,999	260,077
10 - 20	20,796	33,861	266,687	561,726	55,791	368,790
20 - 30	8,122	16,448	415,912	259,141	61,938	89,097
30 - 40	6,731	15,149	319,680	147,314	39,224	73,359
40 - 50	6,057	22,737	230,316	114,005	52,318	41,511
50 - 60	6,221	12,542	187,293	296,558	21,271	46,368
60 - 70	3,092	42,507	30,576	169,084	30,652	35,426
70 - 80	10,223	3,952	130,529	42,672	11,993	34,507
80 - 90	6,236	26,341	27,734	59,885	21,866	8,132
90 - 100	2,545	4,690	163,658	123,069	11,629	24,313
100 - 110	13,516	5,116	26,496	143,361	13,967	52,805
110 - 120	2,049	32,070	80,433	120,914	14,856	9,397
120 - 130	3,657	942	136,215	52,796	36,833	7,200
130 - 140	465	2,040	159,330	7,810	2,631	8,554
140 - 150	1,056	8,866	9,889	20,569	9,489	9,930
150 - 160	10,928	5,589	699	9,366	37,975	16,832
160 - 170	536	2,610	15,893	34,191	11,759	2,208
170 - 180	3,330	780	1,380	37,774	12,784	1,923
180 - 190	1,701	3,055	40,912	9,847	2,945	9,364
190 - 200	3,009	1,597	16,093	32,717	2,926	11,293
200 - 250	4,691	10,981	22,796	199,384	38,157	12,118
250 - 300	2,333	5,849	33,267	103,864	14,683	18,227
300 - 400	8,166	12,931	14,581	72,193	18,759	52,596
400 - 500	3,020	2,336	11,141	62,203	19,659	23,462
500 - 750	2,077	5,753	11,028	29,966	9,048	14,670
750 - 1,000	2,213	13,313	6,853	15,890	26,499	8,578
> 1,000	5,176	6,541	6,543	133,702	25,666	22,650

[56] Increasing the granularity of the cost bundles between the 2011 IRP and 2013 IRP increased the number of total bundles within each state and load bubble from 9 to 27, respectively.

Table 6.21 – Class 2 DSM Adjusted Prices by Cost Bundle

Bundle	Levelized Cost after Adjustments ($/MWh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	-	-	-	-	-	-
10 - 20	-	-	-	-	-	0.74
20 - 30	8.51	3.55	-	3.57	1.00	7.23
30 - 40	17.37	4.13	9.46	13.26	5.64	13.25
40 - 50	26.86	27.26	17.56	23.78	11.15	25.76
50 - 60	31.84	30.41	32.82	35.81	22.65	38.16
60 - 70	34.19	37.68	35.17	45.22	36.98	47.20
70 - 80	52.23	54.64	48.43	52.69	50.94	57.00
80 - 90	62.51	67.31	56.88	68.38	58.82	59.73
90 - 100	81.20	74.33	71.77	78.11	60.15	76.73
100 - 110	86.79	81.74	80.39	81.02	69.50	88.13
110 - 120	96.96	89.80	87.42	78.39	73.89	100.24
120 - 130	106.58	100.81	91.07	107.36	93.44	104.28
130 - 140	98.03	107.05	105.26	112.48	107.35	116.42
140 - 150	119.39	127.24	113.15	122.43	121.51	122.24
150 - 160	131.33	136.23	103.06	133.11	129.27	136.85
160 - 170	147.79	147.73	141.29	136.84	139.10	142.66
170 - 180	150.00	147.84	101.76	156.05	106.49	154.47
180 - 190	164.92	168.18	156.50	157.52	154.22	169.48
190 - 200	174.69	168.42	160.34	173.06	168.43	172.27
200 - 250	211.04	198.24	202.41	210.35	204.53	198.20
250 - 300	255.99	250.90	244.55	233.09	239.56	258.98
300 - 400	329.67	334.22	306.16	316.09	316.61	342.23
400 - 500	408.29	419.68	403.00	430.59	420.65	442.96
500 - 750	601.51	592.73	557.54	513.73	603.17	578.06
750 - 1,000	827.70	895.12	772.20	863.26	798.91	802.18
> 1,000	3,620.28	2,315.69	2,548.01	3,841.62	2,672.86	3,614.73

To capture the time-varying impacts of Class 2 DSM resources, each bundle has an annual 8,760 hourly load shape specifying the portion of the maximum capacity available in any hour of the year. These shapes are created by spreading measure-level annual energy savings over 8,760 load shapes, differentiated by state, sector, market segment, and end use accounting for the hourly variance of Class 2 DSM impacts by measure. These hourly impacts are then aggregated for all measures in a given bundle to create a single weighted average load shape for that bundle.

The load shape is composed of fractional values that represent each hour's demand divided by the maximum demand in any hour for that shape. For example, the hour with maximum demand would have a value of 1.00 (100 percent), while an hour with half the maximum demand would have a value of 0.50 (50 percent). Summing the fractional values for all of the hours, and then multiplying this result by non-coincident peak-hour demand, produces the annual energy savings represented by the supply curve.

To plan for DSM, a planning capacity factor is input into the System Optimizer model for each bundle and year. To determine the planning capacity factor, an average of the capacity for hours 14 through 19 during the average July day is divided by the overall maximum capacity value during the year for each bundle and year.

An accelerated Class 2 DSM acquisition scenario was created for inclusion in three of the IRP core cases. Although the total available potential over the 20-year planning period did not change for this scenario, discretionary resource acquisition was accelerated and market ramp rates were removed[57] to allow the System Optimizer model to select up to two percent of retail sales annually in each state until discretionary resources were exhausted. In this scenario, the costs for accelerated measures were increased to acknowledge that such a scenario would likely require higher incentive and non-incentive program expenditures to expand participation and delivery infrastructure[58].

Distribution Energy Efficiency

In 2012, the Company conducted a pilot to assess the feasibility of distribution energy efficiency for four circuits in Washington. Of the 0.09 aMW predicted to be acquired through the pilot, less than 0.01 aMW was actually achieved. The pilot was not cost effective. Less than half of the anticipated reduction in average voltage was achieved, and the estimated cost of energy savings was $112.49/MWh. Following the pilot, the Company screened all active distribution circuits in Oregon, Idaho, Wyoming, and Utah and found that between 0 and 0.2 aMW of conservation voltage reduction energy savings might exist within the Company's service territory in those four states. However, it is likely that pursuing measures in those states would not be cost effective. Two key lessons from the pilot and subsequent screening effort are:

1) Most of the Company's circuits are already operating at a relatively low voltage and improvements necessary to allow an even lower voltage are not usually justified by the value of the energy saved.

2) Small amounts of saved energy on the utility system cannot be accurately and repeatably measured due to the dynamic interplay between the system and the customers' requirements.

Distribution energy efficiency measures were not modeled as potential resources in this IRP, since the Company found through its pilot that savings from such measures are unreliable and generally not cost-effective. Further details on this pilot and its conclusions are provided in Appendix E.

[57] Hypothetical adjustments to real world constraints were made in order to provide sufficient Class 2 DSM resources to allow the model to select up to 2 percent of retail sales in each state.

[58] The resource cost adjustments in the accelerated DSM scenario may not represent the actual costs of such a scenario; there was limited information available to inform the Company what costs would be required to facilitate this level of customer participation in markets with low retail rates and limited capital.

Transmission Resources

For this IRP, PacifiCorp investigated five Energy Gateway scenarios, consisting of various combinations of transmission segments. Detailed information on the scenarios and associated modeling approach and findings are provided in Chapter 4.

In this IRP, adjustments to fixed O&M costs were developed to model the additional costs of transmission upgrades to interconnect certain supply-side resources to the Company's system. Table 6.22 below shows fixed O&M cost associated with these transmission upgrades by resource and location.

Table 6.22 – Transmission Upgrades by Supply-Side Resource and Location

Fuel	Resource	Location	Elevation (AFSL)	Transmission Cost Stated in 2012 $/kw-year
Natural Gas	SCCT Aero x3, ISO	Portland / North Coast	0	$37.92
Natural Gas	Intercooled SCCT Aero x1, ISO		0	$37.92
Natural Gas	SCCT Frame "F" x1, ISO		0	$37.92
Natural Gas	IC Recips x6, ISO		0	$37.92
Natural Gas	CCCT Dry "F", 2x1, ISO		0	$37.92
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		0	$37.92
Natural Gas	CCCT Dry "G/H", 1x1, ISO		0	$37.92
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		0	$37.92
Natural Gas	CCCT Dry "G/H", 2x1, ISO		0	$37.92
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		0	$37.92
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		0	$37.92
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		0	$37.92
Natural Gas	SCCT Aero x3, ISO	Willamette Valley	0	$55.12
Natural Gas	Intercooled SCCT Aero x1, ISO		0	$55.12
Natural Gas	SCCT Frame "F" x1, ISO		0	$55.12
Natural Gas	SCCT Aero x3, ISO	Walla Walla	1,500	$3.51
Natural Gas	Intercooled SCCT Aero x1, ISO		1,500	$3.51
Natural Gas	SCCT Frame "F" x1, ISO		1,500	$3.51
Natural Gas	IC Recips x6, ISO		1,500	$3.51
Natural Gas	CCCT Dry "F", 2x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "G/H", 1x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "G/H", 2x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		1,500	$3.51
Natural Gas	CCCT Dry "G/H", 1x1, ISO	Yakima	1,500	$3.51
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		1,500	$3.51
Natural Gas	SCCT Frame "F" x1, ISO		1,500	$3.51
Natural Gas	Intercooled SCCT Aero x1, ISO		1,500	$3.51
Natural Gas	SCCT Aero x3, ISO	Salt Lake Valley	4,250	$12.80
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	$12.80
Natural Gas	SCCT Frame "F" x1, ISO		4,250	$12.80
Natural Gas	IC Recips x6, ISO		4,250	$12.80
Natural Gas	CCCT Dry "F", 2x1, ISO		4,250	$12.80
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		4,250	$12.80
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	$12.80
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	$12.80
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	$12.80
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	$12.80
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	$12.80
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	$12.80
Natural Gas	SCCT Aero x3, ISO	Eastern Wyoming	4,250	$29.32
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	$29.32
Natural Gas	SCCT Frame "F" x1, ISO		4,250	$29.32
Natural Gas	IC Recips x6, ISO		4,250	$29.32
Natural Gas	CCCT Dry "F", 2x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	$29.32
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	$29.32

Table 6.22 – Transmission Upgrades by Supply-Side Resource and Location (Continued)

Fuel	Resource	Location	Elevation (AFSL)	Transmission Cost Stated in 2012 $/kw-year
Natural Gas	SCCT Aero x3, ISO	Idaho	4,250	$3.44
Natural Gas	Intercooled SCCT Aero x1, ISO		4,250	$3.44
Natural Gas	SCCT Frame "F" x1, ISO		4,250	$3.44
Natural Gas	IC Recips x6, ISO		4,250	$3.44
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	$3.44
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	$3.44
Natural Gas	SCCT Aero x3, ISO	Southern	4,250	$18.96
Natural Gas	Intercooled SCCT Aero x1, ISO	Oregon	4,250	$18.96
Natural Gas	SCCT Frame "F" x1, ISO		4,250	$18.96
Natural Gas	IC Recips x6, ISO		4,250	$18.96
Natural Gas	CCCT Dry "F", 2x1, ISO		4,250	$18.96
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		4,250	$18.96
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	$18.96
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	$18.96
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	$18.96
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	$18.96
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	$18.96
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	$18.96
Natural Gas	SCCT Aero x3, ISO	Utah	4,250	$7.94
Natural Gas	Intercooled SCCT Aero x1, ISO	South	4,250	$7.94
Natural Gas	SCCT Frame "F" x1, ISO		4,250	$7.94
Natural Gas	IC Recips x6, ISO		4,250	$7.94
Natural Gas	CCCT Dry "F", 2x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "G/H", 2x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		5,050	$7.94
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		5,050	$7.94
Natural Gas	Intercooled SCCT Aero x1, ISO	SW	6,500	$12.27
Natural Gas	SCCT Frame "F" x1, ISO	Wyoming	6,500	$12.27
Natural Gas	IC Recips x6, ISO		6,500	$12.27
Natural Gas	CCCT Dry "F", 2x1, ISO		5,050	$12.27
Natural Gas	CCCT Dry "F", DF, 2x1, ISO		5,050	$12.27
Natural Gas	CCCT Dry "G/H", 1x1, ISO		5,050	$12.27
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO		5,050	$12.27
Natural Gas	CCCT Dry "G/H", 2x1, ISO		6,500	$12.27
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO		6,500	$12.27
Natural Gas	CCCT Dry "J", Adv 1x1, ISO		6,500	$12.27
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO		6,500	$12.27
Coal	IGCC with CCS	Wyoming	6,500	$29.32
Geothermal	Generic Geothermal PPA 90% CF	OT/UT	4,500	$0.00
Wind	2.3 MW turbine 29% CF (EG 1, 2 and 4	WA/OR	1,500	$35.07
Wind	2.3 MW turbine 29% CF (EG 3 and 5)	WA/OR	1,500	$0.00
Wind	2.3 MW turbine 29% CF	Utah	4,500	$7.94
Wind	2.3 MW turbine 29% CF	Idaho	4,500	$3.44
Wind	2.3 MW turbine 40% CF	Wyoming	6,500	$0.00
Solar	PV Poly-Si Fixed Tilt 22% CF	Various	4,500	$0.00
Solar	PV Poly-Si Fixed Tilt 28% CF	Utah	4,500	$6.99
Solar	PV Poly-Si Single Tracking 33% CF	Utah	4,500	$6.99
Biomass	Forestry Byproduct	Various	1,500	$0.00
Storage	Pumped Storage	Utah South	4,500	$17.83
Storage	Sodium-Sulfur Battery	Various	4,500	0
Storage	Advanced Fly Wheel	Various	4,500	0
Storage	CAES	SW Wyoming	4,500	$8.57
Nuclear	Advanced Fission	Utah	4,500	$25.12

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions.

As proxy resources, FOTs represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range of volumes and terms for these transactions.

Solicitations for FOTs can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

Two FOT types were included for portfolio analysis: an annual flat product, and a HLH third quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, six days per week from July through September. Because these are firm products the counterparties supply the reserves; and back the supply. For example, a 100 MW front office purchase requires the seller to deliver 100 MW to PacifiCorp regardless of circumstance.[59] Thus, to insure delivery, the seller must hold the required level of reserves as warranted by its system to insure supply. For this reason, PacifiCorp does not need to hold additional reserves on its 100 MW firm front office purchase. Table 6.23 shows the FOT resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability.

Table 6.23 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2013-2032
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2013-2032
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour ("6x16")	100 MW, 2013-2032

[59] Typically, the only exception would be under force majeure. Otherwise, the seller is required to deliver the full amount even if the seller has to acquire it at an exorbitant price.

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mead 3 rd Quarter, Heavy Load Hour (6x16)	190 MW, 2013-2014 0 MW, 2015+
Mona 3 rd Quarter, Heavy Load Hour (6x16)	300 MW, 2013+

To arrive at these maximum quantities, PacifiCorp considered the following:

- Historical operational data and institutional experience with transactions at the market hubs.
- The Company's forward market view, including an assessment of expected physical delivery constraints and market liquidity and depth.
- Financial and risk management consequences associated with acquiring purchases at higher levels, such as additional credit and liquidity costs.

Prices for FOT purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

- The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. The 2013 IRP modeling approach consists of eight phases, from defining scenarios for portfolio development—referred to as "cases," to final selection of preferred portfolio based on costs and risk measures.
- PacifiCorp worked closely with stakeholders to define 19 core cases that were applied uniformly across five Energy Gateway transmission scenarios and developed an additional 12 sensitivity cases reflecting alternative assumptions for load forecasts, availability of renewable resource federal tax incentives, renewable portfolio standard modeling, Class 3 demand-side management (DSM) resource availability, and coal unit environmental investments. In total 106 portfolios, each analyzing unit-by-unit environmental investments in existing coal resources, were developed and risk assessment studies were completed for 37 portfolios among three carbon dioxide (CO_2) tax levels.
- Three underlying natural gas price forecasts (low, medium, and high) were used to develop gas price projections consistent with a range of CO_2 price assumptions: zero, medium, and high, plus U.S. hard cap prices required for the power sector to achieve an 80% reduction in emission by 2050 using both medium and high natural gas price assumptions.
- Top-performing portfolios were selected on the basis of system costs using Monte Carlo simulations over a twenty year planning horizon. The Monte Carlo runs capture stochastic behavior of electricity prices, natural gas prices, loads, thermal unit availability, and hydro availability across 100 iterations.
- Final preferred portfolio selection considers additional criteria such as risk-adjusted portfolio cost, CO_2 emissions, supply reliability, resource diversity, and attainability of DSM program and renewable portfolio standard (RPS) requirements.

Introduction

The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation. This chapter describes the modeling and risk analysis process that supported that portfolio performance evaluation. The information drawn from this process, summarized in Chapter 8, was used to determine PacifiCorp's preferred portfolio and support the analysis of resource acquisition risks.

The 2013 IRP modeling approach consists of eight phases, depicted as a flow chart in Figure 7.1. The eight phases are as follows:

(1) Define input scenarios, referred to as cases, characterized by varying assumptions for CO_2 prices, commodity gas prices, wholesale electricity prices, coal prices, environmental policy and other cost drivers.

(2) Case-specific price forecast development, where natural gas and power price assumptions are developed consistent with the definitions for each case.

(3) Optimized portfolio development for each case that excludes RPS assumptions using PacifiCorp's System Optimizer capacity expansion model.

(4) Development of a renewable resource floor, reflecting renewable resource additions chosen in optimized portfolios, developed in Phase 3 of the modeling approach, that meet RPS requirements in cases that include RPS assumptions. This is a new step in the modeling process for the 2013 IRP that relies upon the RPS Scenario Maker model.

(5) Optimized portfolio development for each case that includes RPS assumptions using PacifiCorp's System Optimizer capacity expansion model requiring renewable resource additions that include at least those renewable resources developed in Phase 4 of the modeling approach.

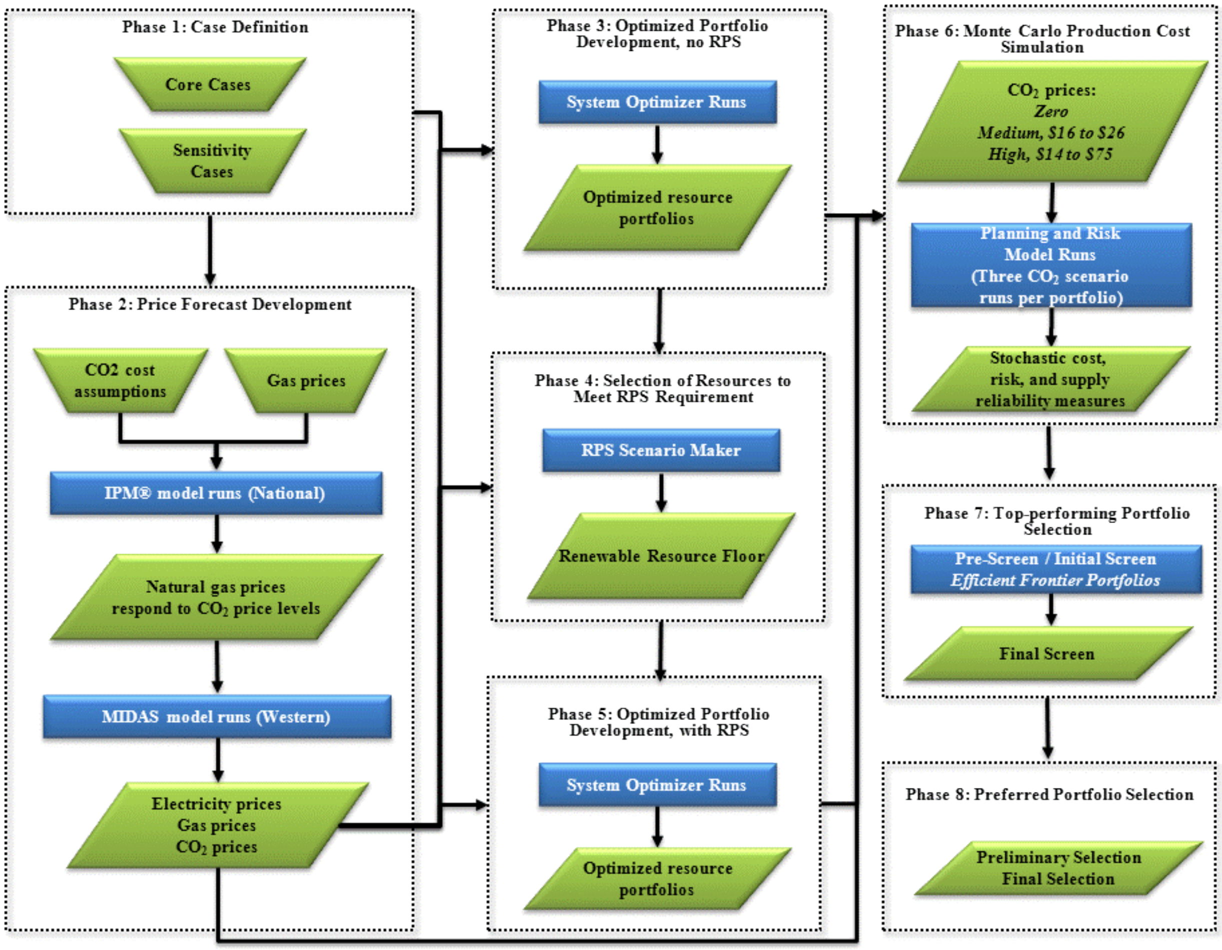
(6) Monte Carlo production cost simulation of optimized portfolios using PacifiCorp's Planning and Risk (PaR) model to support stochastic risk analysis.

(7) Selection of top-performing portfolios using a three-phase screening process (preliminary screening, initial screening, and final screening) that incorporates stochastic portfolio cost and risk assessment measures, and

(8) Preliminary preferred portfolio selection followed by final selection of the preferred portfolio.

This chapter describes the overall modeling approach, including a discussion of modeling and price assumptions, and provides a profile of each modeling phase described above.

Figure 7.1 – Modeling and Risk Analysis Process



Portfolio Modeling: System Optimizer

The System Optimizer model operates by minimizing for each year the operating costs for existing resources, taking into consideration potential compliance alternatives to coal unit environmental investments, subject to system load balance, reliability and other constraints. Over the 20-year study period, it optimizes resource additions subject to resource investment and capacity constraints (monthly peak loads plus a planning reserve margin for each load area represented in the model). In the event that early retirement of a coal unit is a lower cost alternative to installation of coal unit environmental investments, the System Optimizer model will select additional resources as required to meet monthly peak loads inclusive of a planning reserve margin.

To accomplish these optimization objectives, the model performs a time-of-day least-cost dispatch for existing and potential planned generation, contract, DSM, and transmission resources. The dispatch is based on a representative-week method. Time-of-day hourly blocks are simulated according to a user-specified day-type pattern representing an entire week. Each month is represented by one week, with results scaled to the number of days in the month and then the number of months in the year. The dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the overall PVRR, consisting of the net present value of contract and spot market purchase costs, generation costs (fuel, fixed and variable operation and maintenance, unserved energy, and unmet capacity), and amortized capital costs for planned resources.

Modeling Capital Costs and Addressing "End-Effects"

For capital cost derivation, System Optimizer uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects issues associated with capital-intensive investments that have different lives and in-service dates. All capital costs evaluated in the IRP are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred methodology to account for analysis of capital investment decisions that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given investment decision. To achieve this, the real levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that grows at inflation such that the PVRR is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For the 2013 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2032 planning period. PacifiCorp uses the real-levelized capital costs produced by System Optimizer for portfolio cost reporting by the PaR model.

In prior IRPs, growth station resources were included as generic resource alternatives in the out years of the IRP planning horizon. Historically, this resource option was used to balance capacity in each load area as a means to manage simulation run times by simplifying resource selection beyond the first 10 years of the planning period. Growth stations were ascribed costs derived from the forward power price curve. Upon expanding the scope of the 2013 IRP to evaluate coal unit environmental investments in all System Optimizer simulations, the use of growth resources was eliminated, allowing selection of supply and demand side resource alternatives in meeting loads over the entire 20 year planning horizon. This approach is required to ensure that the economics of potential early coal unit retirements capture the full cost of replacement resources over the long-term.

Modeling Front Office Transactions

Front office transactions (FOTs) are assumed to be transacted on a one-year basis, and are represented as available in each year of the study. For capacity optimization modeling, System Optimizer engages in market transactions. FOT transactions are firm forward power purchases that contribute capacity and energy to the system. System balancing transactions are short-term purchases and sales used to balance energy supply with demand in all hours across the system. System balancing purchases are energy transactions and do not contribute in meeting system capacity and planning reserve margin needs.

The FOTs modeled in the PaR model generally have the same characteristics as those modeled in the System Optimizer, except that transaction prices reflect wholesale forward electric market prices that are "shocked" according to a stochastic modeling process prior to simulation execution.

Modeling Wind and Solar Resources

Wind and solar resources are modeled as non-dispatchable, must-run resources in both the System Optimizer and PaR models using fixed energy profiles that vary by month and time of day. The total energy generation for wind and solar resources represents the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels.

In this IRP, the peak contribution of the wind resources is set at 4.2 percent, which was determined based upon review of actual wind generation data interconnected to PacifiCorp's system. The peak contribution of solar resources is set at 13.6 percent, which is based on third party information due to the lack of sufficient actual solar resource generation data within the Company's system. Volume II, Appendix O of this report discusses the details of the methodology that determined the peak contribution assumptions for wind and solar resources.

Modeling Coal Unit Environmental Investments

Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process for the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations are considered in the development of all resource portfolios. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. This advancement in analytical approach marks a significant evolution of the IRP process as it requires consideration of potential resource *contraction* while simultaneously analyzing alternative resource expansion plans.

Integrating coal unit environmental investment decisions in the development of resource portfolios identifies whether investments are cost effective in relation to other compliance alternatives. However, additional analysis is required to numerically quantify the economic benefit of investment decisions required on any given unit as compared to the next best alternative. Confidential Volume III summarizes additional analysis of coal unit environmental investments that are used to quantify the economic benefits of specific investment decisions that have been analyzed in the development of resource portfolios for the 2013 IRP.

Table 7.1 outlines the type of costs that are assigned to existing coal units configured with early retirement and gas conversion alternatives.

Table 7.1 – Resource Costs, Existing and Associated Gas Conversion Alternatives

Existing Coal Unit Costs	Coal Unit Early Retirement Alternative	Gas Conversion Alternative
• Incremental capital for environmental investments • Variable reagent costs for incremental environmental investments • Run-rate operations & maintenance (O&M) and capital • Incremental mine capital (as applicable) • Cash coal fuel costs • End-of-life decommissioning	• Decommissioning costs • Recovery of incremental environmental capital and run-rate capital spent prior to early retirement date • Coal contract liquidated damages (as applicable)	• Up-front capital cost • Run-rate operations & maintenance (O&M) • Fixed and variable natural gas transportation • Natural gas fuel cost • Recovery of incremental environmental capital and run-rate capital spent prior to gas conversion • Coal contract liquidated damages (as applicable)

Reserve Margin Requirement

In the System Optimizer model, PacifiCorp continues to apply a 13 percent planning reserve margin. The planning reserve margin is used to ensure that the Company has sufficient resources to meet peak loads recognizing that there is a possibility for load fluctuation and extreme weather conditions, a possibility for unplanned resource outages, and a requirement to carry contingency and regulating reserves.

In the PaR model, explicit categories of operational reserve requirements are modeled. The contingency reserves are approximately 7 percent of the system load. The amount of regulating reserves includes ramping of load, as well as requirement to integrate variable energy resources, such as wind. The reserve requirements to integrate wind resources are the results of PacifiCorp's 2012 Wind Integration Study, which is presented in Volume II, Appendix H of this report. The forced outages and fluctuation in load due to temperature are reflected in the modeling of resource availability and simulated in the stochastic runs.

Modeling Energy Gateway Transmission Scenarios

The Energy Gateway transmission project is modeled in this IRP under five scenarios. The scenarios for Energy Gateway transmission paths are modeled as fixed inputs to both the System Optimizer and PaR models, which cannot endogenously add additional transmission resources as can be done for supply and demand side resources. The costs of Energy Gateway segments are modeled as a real levelized revenue requirement, as discussed above, based on a real levelized capital recovery factor of 7.069 percent, which intends to recover the investment cost of the assets, return on and of capital, income taxes and property taxes. Fixed operating and maintenance costs are also included in the model as 1.07 percent of the investment.

Modeling Energy Storage Technologies

Energy storage resources in both System Optimizer and PaR models are distinguished from other resources by the following three attributes:

- Energy "take" – generation or extraction of energy from a reservoir on-peak;
- Energy "return" – energy used to fill (or charge) a reservoir off-peak; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

The models require specification of a reservoir size. For System Optimizer and PaR models, reservoir size is defined in gigawatt-hours. System Optimizer dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the model accounts for conventional generation system performance and cost characteristics of the storage resource, including investment cost, capacity factor, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity.

In the PaR model, simulations are conducted on a week-ahead basis. The model operates the storage plant to balance generation and charging, accounting for cycle efficiency losses, in order to end the week in the same net energy position as it began. The model chooses periods to generate and return energy to minimize system cost. It does this by calculating an hourly *value of energy* for charging. This value of energy, a form of marginal cost, is used as the cost of generation for dispatch purposes, and is derived from calculations of system cost and unit commitment effects. For compressed air energy storage (CAES) plants, a heat rate is included as a parameter to capture fuel conversion efficiency. The heat rates entered in both models represent the use of PacifiCorp's off-peak coal-fired plants.

General Assumptions and Price Inputs

Study Period and Date Conventions

PacifiCorp executes its IRP models for a 20-year period beginning January 1, 2013 and ending December 31, 2032. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, with the exception of natural gas conversion alternatives to incremental environmental investments required at existing coal units, which are given an in-service date of June 1st for the year gas conversion is completed.

Escalation Rates and Other Financial Parameters

Inflation Rates

The IRP model simulations and price forecasts reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. For the System Optimizer model, a single escalation rate value is used. This value, 1.9 percent, is estimated as the average of the annual corporate inflation rates for the period 2013 to 2032, using PacifiCorp's March 2012 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product (GDP) inflator and Consumer Price Index (CPI).

Discount Factor

The rate used for discounting in financial calculations is PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2013 IRP is 6.882 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[60]

Federal Renewable Resource Tax Incentives

In the current IRP, it is assumed that federal production tax credits (PTC) for qualifying renewable resources are expired and that the federal investment tax credits (ITC) for qualifying renewable resources will expire at the end of 2016, consistent with the Emergency Economic Stabilization Act of 2008 (P.L. 110-343), which allows utilities to claim the 30 percent ITC for solar facilities placed in service by January 1, 2017. This tax credit is factored into the capital cost for solar resource options in the System Optimizer model. Select cases evaluated for the 2013 IRP assume federal PTCs and ITCs are extended through 2019.

Asset Lives

Table 7.2 lists the generation resource asset book lives assumed for levelized fixed charge calculations.

[60] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 7.2 – Resource Book Lives

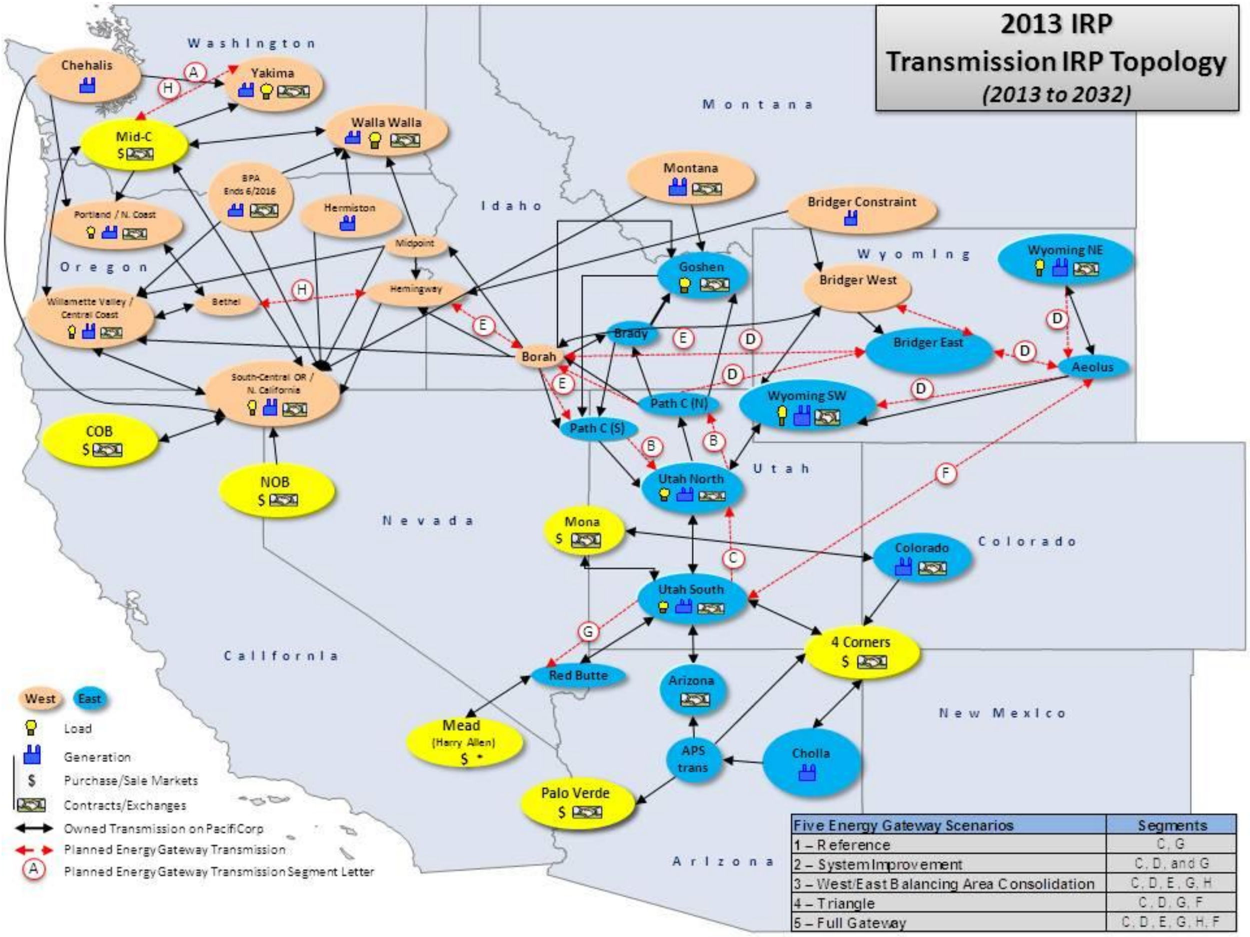
Resource	Book Life (Years)
Integrated Gasification Combined-Cycle with carbon capture and sequestration	40
Combined Cycle Combustion Turbine (CCCT)	40
Pumped Storage	50
Simple Cycle Combustion Turbine (SCCT) Frame	35
Solar Photovoltaic	25
Solar Thermal	30
Compressed Air Energy Storage	30
Single Cycle Combustion Turbine (SCCT) Aero	30
Intercooled Aeroderivative SCCT	30
Internal Combustion Engine	20
Fuel Cells	20
Wind	25
Battery Storage	30
Biomass	30
Nuclear Plant	40
CHP - Reciprocating Engine	20
CHP - Gas Turbine	20
CHP - Microturbine	10
CHP - Fuel Cell	10
CHP - Commercial Biomass, Anaerobic Digester	17
CHP - Industrial Biomass Waste	17
Solar - Rooftop Photovoltaic	30
Solar - Water Heaters	20

Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (electrically connected areas) in its eastern balancing authority area and 18 bubbles in its western balancing authority area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant's current firm rights on the transmission lines. This topology is defined for both the System Optimizer and PaR models.

Figure 7.2 shows the IRP transmission system model topology. Segments of the planned Energy Gateway Transmission Project are indicated with red dashed lines and with alphabetic names.

Figure 7.2 – Transmission System Model Topology



The most significant change to the model topology from the 2011 IRP is the addition of four new bubbles and the identification of the Energy Gateway line segments.

- The Hemingway bubble addition was essential for modeling the Energy Gateway path "H" of Hemingway-Boardman-Bethel with bi-directional capabilities, and to improve the ability to model the separate transfer capability through the Idaho Power system.
- The Midpoint-Meridian bubble addition is an improved representation of existing east to west transfer capability. This modeling of the legacy contract is needed since it contains provisions limiting what energy may be transferred on the west side of the Idaho Power system.
- The Bridger Constraint bubble addition is included to model a reliability constraint consistent with operations that limits the transfer from Jim Bridger to the east balancing authority area to three of the four generating units.
- The Nevada Oregon Border (NOB) bubble addition is to provide existing access to the California ISO market via PacifiCorp's DC Intertie rights in the model. Without this addition the benefits of the existing rights would not be apparent.

The 2011 IRP utilized separate wind bubbles in order to assign incremental transmission interconnection investment costs to the wind resources. However, in the current IRP, the incremental transmission costs are assigned directly to the wind resources and, therefore, eliminated the need to model separate wind bubbles.

Carbon Dioxide Regulatory Compliance Scenarios

Carbon Dioxide Scenarios

Table 7.3 shows five different sets of CO_2 price assumptions used in the 2013 IRP. Each CO_2 price scenario is accompanied by a consistent set of natural gas and wholesale power price assumptions. For modeling purposes, the cost of CO_2 emissions are applied as a tax in which there is a cost imputed on each ton of CO_2 emissions generated by system resources. This approach is used in recognition that there are a wide range of policy mechanisms that might be used to regulate CO_2 emissions in the power sector at some point in the future. Application of CO_2 prices as a tax is a means to assign costs to CO_2 emissions as a surrogate for a wide range of potential future policy tools, whether implemented as a tax, cap-and-trade program, emission performance standards, or some other policy mechanism. Each of the CO_2 price scenarios used in the 2013 IRP is discussed in turn below:

Zero CO_2 Price Scenario

Given that there is currently no specific legislative proposal that has been passed by Congress for the President's consideration and no current federal regulation that would impose a direct cost on CO_2 emissions, the 2013 IRP includes a zero CO_2 price scenario. Under this scenario, there is no direct cost applied to CO_2 emissions from generation sources throughout the IRP 20-year planning horizon.

Medium CO_2 Price Scenario

The medium CO_2 price scenario ascribes a cost to CO_2 emissions within ten years of 2013, and as such, prices are assumed beginning in 2022. Price levels in this scenario are consistent with recent projections from third party forecasters. Price levels in the medium CO_2 price scenario are generally aligned with a price signal that would be required to induce switching from coal to natural gas-fired generation sources with an assumed annual real escalation rate of 3 percent.

High CO_2 Price Scenario

Under the high CO_2 price scenario, a cost is ascribed to CO_2 emissions beginning 2020, which is two years earlier than in the medium CO_2 price scenario. Under the high scenario, it is assumed that regulation would ramp into more stringent requirements over the first two years (in 2020 and 2021). The high scenario reflects how prospective CO_2 prices might respond to a future with new regulations that would impose costs on fossil fuel sources and new regulations that could increase natural gas prices (i.e. regulations that would increase the cost of natural gas supply). Under such a scenario, the CO_2 price signal required to induce switching from coal to natural gas-fired generation sources would be higher as compared to the medium CO_2 price scenario, and the resulting price trajectory is similar to the price ceiling that was included in a climate and energy bill proposed by Senator John Kerry and Senator Joe Lieberman in the American Power Act of 2010.

U.S. Hard Cap, Medium Natural Gas CO_2 Price Scenario

This scenario reflects a CO_2 price trajectory produced using the Integrated Planning Model (IPM®) assuming a generic cap-and-trade program is imposed upon the power sector of the U.S.

economy beginning in 2020 with declining annual emission limits that reach 80 percent below 2005 levels by 2050. In this simplified analysis, it was assumed that domestic and international CO_2 offsets could not be used to mitigate power sector emissions, and the resulting CO_2 price projection was developed off of medium natural gas price assumptions.

U.S. Hard Cap, High Natural Gas CO_2 Price Scenario

As in the U.S. hard cap scenario described above, this scenario reflects a CO_2 price trajectory resulting from a cap-and-trade program imposed upon the power sector of the U.S. economy beginning in 2020 with declining annual emission limits that reach 80 percent below 2005 levels by 2050. Similarly, it is assumed that domestic and international offsets cannot be used to mitigate power sector emissions. In this variant of the U.S. hard cap CO_2 price scenario, the CO_2 price projection was developed off of high natural gas price assumptions. With higher natural gas price assumptions, the resulting CO_2 price level is higher than those developed for the U.S. Hard Cap, Medium Natural Gas CO_2 Price Scenario.

Table 7.3 – CO_2 Price Scenarios

Year	CO_2 Price, Nominal $/short ton				
	None	Base	High	Hard Cap, Base Gas	Hard Cap, High Gas
2020	$0.00	$0.00	$13.53	$47.47	$57.08
2021	$0.00	$0.00	$19.68	$50.86	$61.17
2022	$0.00	$16.00	$26.05	$54.49	$65.53
2023	$0.00	$16.78	$32.67	$58.38	$70.21
2024	$0.00	$17.61	$39.52	$62.55	$75.22
2025	$0.00	$18.47	$46.62	$67.01	$80.59
2026	$0.00	$19.37	$49.88	$71.80	$86.34
2027	$0.00	$20.32	$53.37	$76.94	$92.52
2028	$0.00	$21.32	$57.11	$82.44	$99.14
2029	$0.00	$22.36	$61.10	$88.35	$106.24
2030	$0.00	$23.46	$65.38	$94.67	$113.84
2031	$0.00	$24.63	$70.02	$101.55	$122.12
2032	$0.00	$25.86	$74.99	$108.88	$132.25

Figure 7.3 compares the five CO_2 price scenarios graphically, and Table 7.4 shows the U.S. power sector projected carbon emissions through 2050 under the U.S. Hard Cap Scenario.

Figure 7.3 – Carbon Dioxide Price Scenario Comparison

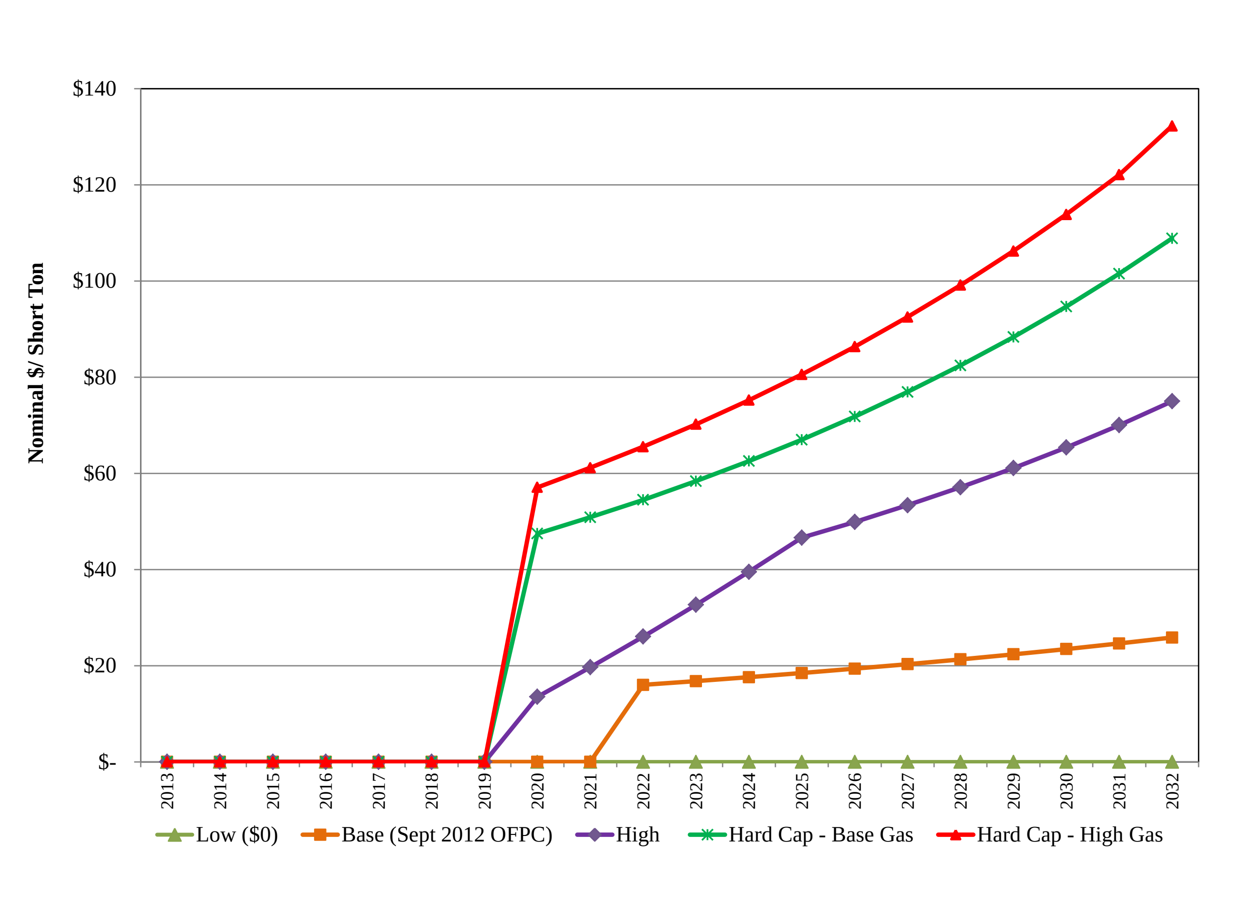


Table 7.4 – Carbon Reduction under U.S. Hard Cap Scenarios

Year	Potential Hard Cap Reduction Scenario: 80% reduction from 2005 CO_2 power sector emission levels by 2050 (short tons)
2005	2,617,960[61]
2020	2,200,511
2021	2,144,614
2022	2,088,716
2023	2,032,819
2024	1,976,922
2025	1,921,024
2026	1,865,127
2027	1,809,230
2028	1,753,333
2029	1,697,435
2030	1,641,538
2031	1,585,641
2032	1,529,743
2033	1,473,846
2034	1,417,949
2035	1,362,052
2050	523,593

Oregon Environmental Cost Guideline Compliance

The Oregon Public Utility Commission (OPUC), in their IRP guidelines, directs utilities to construct a base-case scenario that reflects what it considers to be the most likely regulatory compliance future for CO_2, as well as alternative scenarios "ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities." Modeling portfolios with no CO_2 cost represents the current regulatory level. The base scenario was considered the most likely regulatory compliance scenario at the time that IRP CO_2 scenarios were being prepared and vetted by public stakeholders (early fall of 2012). Given the late-2010 collapse of comprehensive federal energy legislation and loss of momentum for implementing federal carbon pricing schemes, it is not likely Congress will pass federal climate change legislation for consideration by the President over the near-term. At this time, it is likely that federal CO_2 regulations will come in the form of new source performance standards, applicable to both new and existing electric generating units.

PacifiCorp believes that its CO_2 tax and hard cap scenarios reflect a reasonable range of compliance futures for meeting the OPUC scenario development guideline. As discussed in the preceding section, the Company's CO_2 prices are indicative of varying levels of CO_2 prices signals that might arise from a wide range of future policy outcomes at the federal level. Moreover, the System Optimizer model runs using the above CO_2 assumptions yielded varied composition of portfolios, with some portfolios showing nearly all of PacifiCorp's coal units shutting down or converting to natural gas within the 20-year planning horizon.

[61] Energy Information Administration / Emissions of Greenhouse Gases in the United States 2005, November 2006.

Phase (1) Case Definition

The first phase of the IRP modeling process was to define the cases (input scenarios) that the System Optimizer model uses to derive optimal resource expansion plans. The cases consist of variations to inputs representing the predominant sources of portfolio cost variability and uncertainty. PacifiCorp generally specified low, medium, and high values for key assumptions to ensure that a reasonably wide range in potential outcomes is captured. For the 2013 IRP, PacifiCorp worked closely with stakeholders to develop 19 core case definitions applied uniformly across five different Energy Gateway scenarios with an additional 12 sensitivity cases that in total sum to 106 different resource portfolios. Each of the five Energy Gateway scenarios were defined to explore how different combinations of Energy Gateway segments influence resource selection and system costs.

Core cases focus on broad comparability of portfolio performance results for five key variables. These variables include (1) timing of and level of CO_2 prices, (2) natural gas and wholesale electricity prices, (3) policy assumptions pertaining to federal tax incentives and RPS requirements, (4) policy assumptions pertaining to coal unit compliance requirements driven by Regional Haze regulations, and (5) acquisition ramp rates for Class 2 DSM energy efficiency resources.

In contrast, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. The resulting portfolios from the sensitivity cases are typically compared to one of the core case portfolios. PacifiCorp developed 12 sensitivity cases reflecting alternative assumptions for load forecasts, availability of renewable resource federal tax incentives, renewable portfolio standard modeling, Class 3 DSM resource availability, and coal unit environmental investments.

In developing these cases, PacifiCorp worked collaboratively with stakeholders to develop case definitions meeting the following objectives: (1) case definitions expected to yield resource diversity and comparative consistency among cases, (2) portfolio development structure that isolates the how individual Energy Gateway segments affect resource selection, (3) provides for an understanding of how RPS requirements affect renewable resource needs, and (4) is responsive to stakeholder requests targeting specific resource technologies.

With these objectives in mind, the Company initiated the portfolio case development process and sample case definitions at the June 20, 2012 public input meeting. In response to stakeholder comments, the Company produced draft core case definitions at the July 13, 2012 public meeting. Additional stakeholder comments were reviewed and significantly influenced updated draft core case definitions reviewed with stakeholders at the September 14, 2012 meeting. Detailed “fact sheets”, describing high level assumptions for each core case in a consistent format, was shared with stakeholders at the October 24, 2012 meeting and updated at the December 18, 2012 meeting. Sensitivity case fact sheets were shared with stakeholders at the February 27, 2013 public meeting.

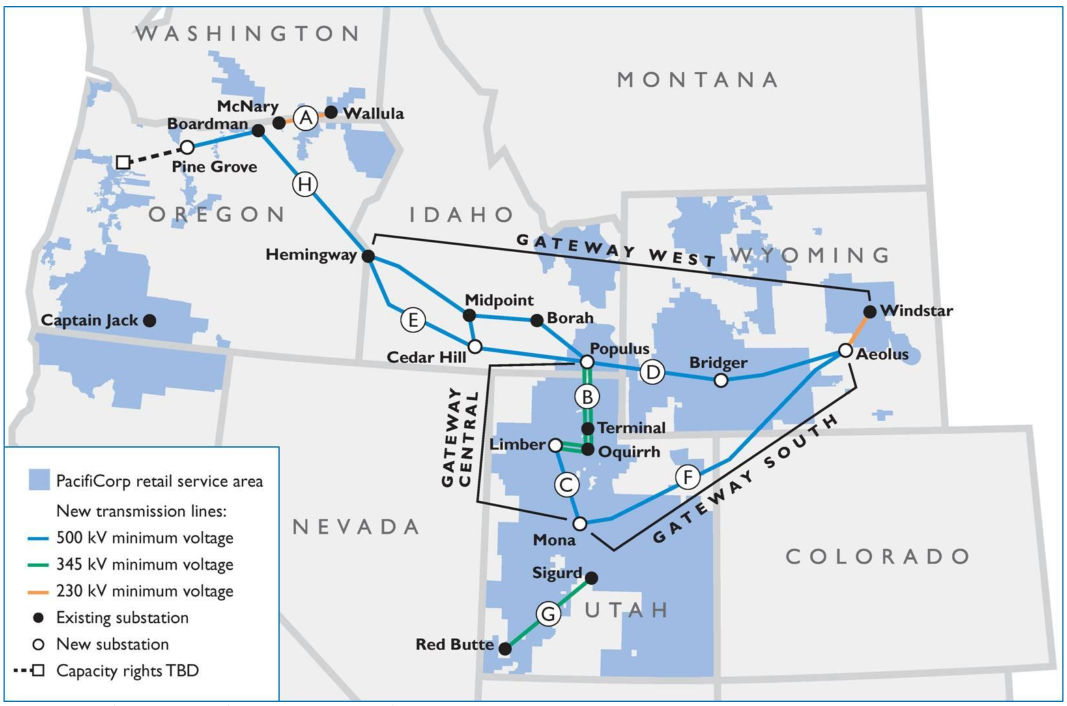
Case Specifications

Table 7.5 defines the five Energy Gateway scenarios, and Figure 7.4 shows the generation location of specific Energy Gateway Segments.

Table 7.5 – Energy Gateway Scenario Definitions

Scenario	Segments	Description
EG1	C and G	**Reference** – Mona-Oquirrh-Terminal, Sigurd-Red Butte
EG2	C, D, and G	**System Improvement** – 2013 Business Plan
EG3	C, D, E, G, and H	**West/East Consolidation** – Increase interchange between PACE and PACW
EG4	C, D, G, and F	**Triangle** – East side wind and improved reliability
EG5	C, D, E, G, H, and F	**Full Gateway** – All Energy Gateway segments

Figure 7.4 – Future Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Portfolio development cases developed for the 2013 IRP were categorized into four different themes, each described in turn below:

(5) Reference: There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy

inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.

(6) Environmental Policy: There are 11 different core cases and two types of sensitivity cases developed for the Environmental Policy Theme. Five of the 11 core cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO_2 prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency. The two types of sensitivity cases developed for the Environmental Policy Theme describe additional analysis performed to evaluate near-term coal unit environmental investments that are summarized in Confidential Volume III.

(7) Targeted Resources: There are four different core cases and five different sensitivity cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four core cases prevents combined cycle resources from being added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four core cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four core cases in this theme assumes a spike in power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth core case in this theme targets clean energy resources and assumes CO_2 prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.

(8) Transmission: The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to the Company's Gateway Segment D project. This case was only analyzed in four of the five Energy Gateway scenarios that include the Gateway Segment D project.

Tables 7.6 and 7.7 provide the definitions of the core cases and sensitivity cases. In addition, detailed descriptions of all cases are provided in case fact sheets that are available in Volume II, Appendix M of this report.

Table 7.6 – Core Case Definitions

Theme	Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Other
Reference	C01	Medium	Medium	Medium	None	Base	n/a
	C02	Medium	Medium	Medium	State	Base	n/a
	C03	Medium	Medium	Medium	State & Federal	Base	n/a
Environmental Policy	C04	Low	High	High	None	Base	n/a
	C05	Low	High	High	State & Federal	Base	n/a
	C06	High	Zero	Low	None	Base	n/a
	C07	High	Zero	Low	State & Federal	Base	n/a
	C08	Low	High	High	None	Base	n/a
	C09	Low	High	High	State & Federal	Base	n/a
	C10	Medium	Medium	Medium	None	Base	n/a
	C11	Medium	Medium	Medium	State & Federal	Base	n/a
	C12	High	Zero	Low	None	Base	n/a
	C13	High	Zero	Low	State & Federal	Base	n/a
	C14	Medium	Hard Cap (Medium Gas)	Medium	State & Federal	Accelerated	n/a
Targeted Resources	C15	Medium	Medium	Medium	State & Federal	Accelerated	No CCCT
	C16	Medium	Medium	Medium	State & Federal	Base	Geothermal/RPS
	C17	High	Medium	Medium	State & Federal	Base	Market Spike
	C18	Medium	Hard Cap (High Gas)	Medium	None	Accelerated	Clean Energy
Transmission	C19	Medium	Medium	Medium	State & Federal	Base	Alt. to Segment D

Table 7.7 – Sensitivity Case Definitions

Theme	Case #	Load	Gas Price	CO2 Price	RPS	PTC/ITC	Coal Investments
Load Sensitivity	S-01	Low	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-02	High	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-03	1 in 20	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Targeted Resource	S-05	Base	Medium	Medium	None	2019/2019	Optimized
	S-06	Base	Medium	Medium	State & Federal (RPS Floor)	2019/2019	Optimized
	S-07	Base	Medium	Medium	State & Federal (Optimized)	2012/2016	Optimized
	S-09	Base	High	High	State & Federal (RPS Floor)	2019/2019	Optimized
	S-10	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Environmental Policy	S-04 (Volume III)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Hypothetical Regional Haze
	S-X (Volume III)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Next Best Alternative

Notes

1. All sensitivity cases are based on Energy Gateway Scenario 2, consistent with the scenario in the 2013 IRP preferred portfolio.
2. Sensitivity Case S-07 applies state RPS targets as system targets in the System Optimizer model. All other sensitivities either use the RPS Scenario Maker to establish a renewable resource floor or exclude RPS requirements altogether.
3. Case S-08 (simulating PacifiCorp's 2013 Business Plan portfolio in the current input setup) was removed due to incompatibilities in how Class 2 DSM resources are modeled in the 2013 IRP.
4. Sensitivity cases S-04 (Hypothetical Regional Haze Compliance Alternative) and S-X (Emission Control PVRR(d) Analysis) are confidential and summarized in confidential Volume III of the 2013 IRP report.

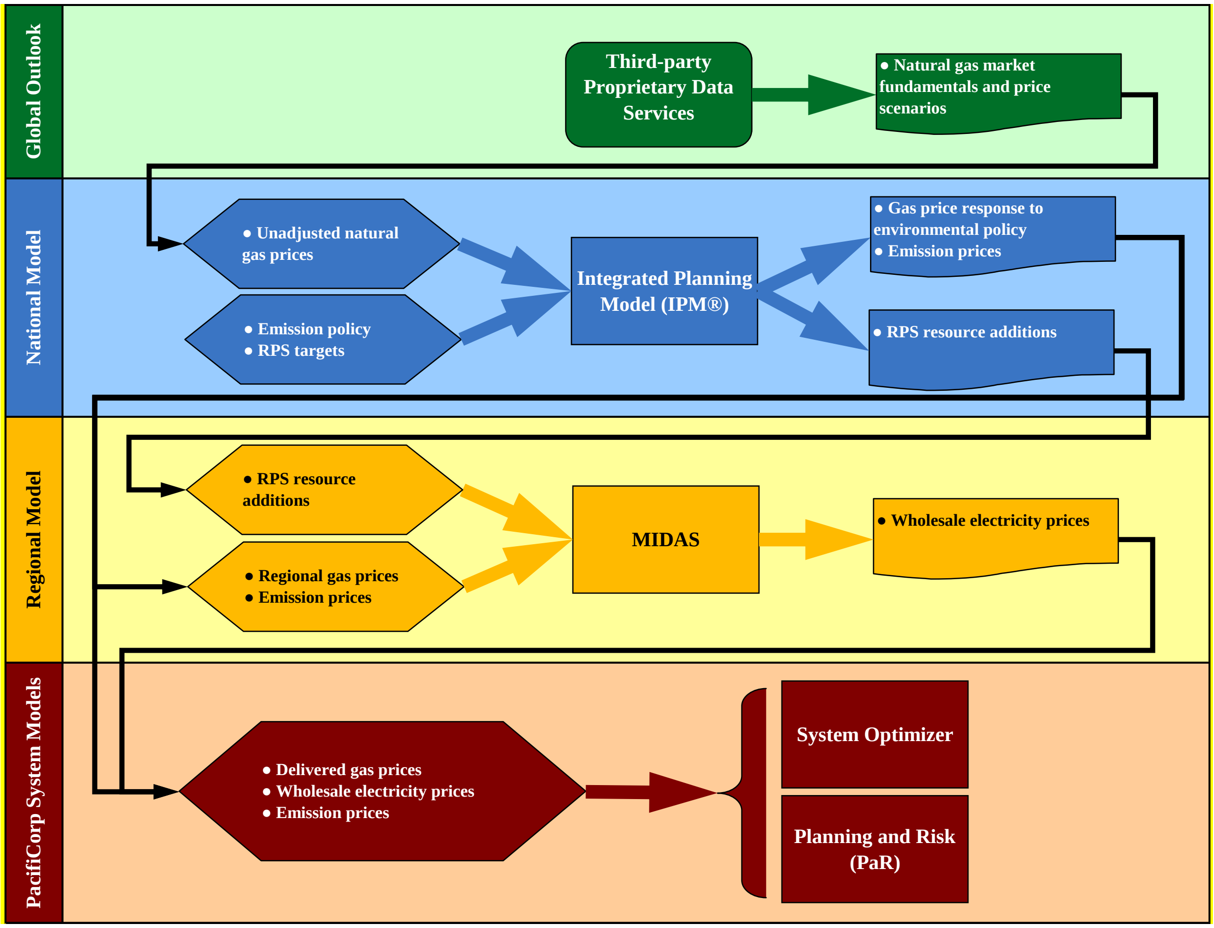
Phase (2) Scenario Price Forecast Development

On a central tendency basis, commodity markets tend to respond to the evolution of supply and demand fundamentals over time. Due to a complex web of cross-commodity interactions, price movements in response to supply and demand fundamentals for one commodity can have implications for the supply and demand dynamics and price of other commodities. This interaction routinely occurs in markets common to the electric sector as evidenced by a strong positive correlation between natural gas prices and electricity prices.

Some relationships among commodity prices have a long historical record that have been studied extensively, and consequently, are often forecasted to persist with reasonable confidence. However, robust forecasting techniques are required to capture the effects of secondary or even tertiary conditions that have historically supported such cross-commodity relationships. For example, the strong correlation between natural gas prices and electricity prices is intrinsically tied to the increased use of natural gas-fired capacity to produce electricity. If for some reason natural gas-fired capacity diminishes in favor of an alternative technology, the linkage between gas prices and electricity prices would almost certainly weaken.

PacifiCorp deploys a variety of forecasting tools and methods to capture cross-commodity interactions when projecting prices for those markets most critical to this IRP – natural gas prices, electricity prices, and emission prices. Figure 7.5 depicts a simplified representation of the framework used by PacifiCorp to develop the price forecasts for these different commodities. At the highest level, the commodity price forecast approach begins at a global scale with an assessment of natural gas market fundamentals. This global assessment of the natural gas market yields a price forecast that feeds into a national model where the influence of emission and renewable energy policies is captured. Finally, outcomes from the national model feed into a regional model where delivered gas prices and emission prices drive a forecast of wholesale electricity prices. In this fashion, the Company is able to produce an internally consistent set of price forecasts across a range of potential future outcomes at the pricing points that interface with PacifiCorp's system.

Figure 7.5 – Modeling Framework for Commodity Price Forecasts



The process begins with an assessment of global gas market fundamentals and an associated forecast of North American natural gas prices. In this step, PacifiCorp relies upon a number of expert third-party proprietary data and forecasting services to establish a range of gas price scenarios. Each price scenario reflects a specific view of how the North American natural gas market will balance supply and demand.

Once a natural gas price forecast is established, the Integrated Planning Model (IPM®) is used to simulate the entire North American power system. IPM®, a linear program, determines the least cost means of meeting electric energy and capacity requirements over time, and in its quest to lower costs, ensures that all assumed emission policies and RPS policies are met. Concurrently, IPM® can be configured with a dynamic natural gas price supply curve that allows natural gas prices to respond to changes in demand triggered by environmental compliance. Additional outputs from IPM® include a forecast of resource additions consistent with all specified RPS targets, electric energy and capacity prices, coal prices[62], electric sector fuel consumption, and emission prices for policies that limit emissions or emission rates.[63]

Once emission prices and the associated gas price response are forecasted with IPM®, results are used in a regional model, Multi Objective Integrated Decision Analysis System (MIDAS), to produce an accompanying wholesale electricity price forecast. MIDAS is an hourly chronological dispatch model configured to simulate the Western Interconnection and offers a more refined representation of western wholesale electricity markets than is possible with IPM®. Consequently, PacifiCorp produces a more granular price projection that covers all of the markets required for the system models used in the IRP. The natural gas and wholesale electricity price forecasts developed under this framework and used in the cases for this IRP are summarized in the sections that follow.

Gas and Electricity Price Forecasts

PacifiCorp's official forward price curve (OFPC) for natural gas prices is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into a third-party fundamentals forecast, starting in month 85.

The first 72 months of the official forward price curve represents market forwards, the value that market participants will buy and sell today for a commodity that delivers sometime in the future. There is a constant consideration for what happens between today and the time of delivery and all days in between as demonstrated by dynamic (constant) changes in bids and offers. A forward curve is not a forecast; it is simply a representation of where one believes they can transact today for forward settlements/deliveries.

In contrast to market forwards, starting in month 85, PacifiCorp's OFPC is based on a third-party fundamentals forecast. This forecast is a single description of what one expects the value a commodity to be at the time it is delivered and consumed. A forecast contains no consideration for what happens between today and the forecast's scope of time.

The underlying base natural gas price forecasts used in this IRP are significantly lower than those produced for the Company's 2011 IRP and the subsequent 2011 IRP Update filed with state commissions March 2011 and March 2012, respectively. Figures 7.6, 7.7, and 7.8 compare base natural gas (Henry Hub) and electricity (Palo Verde and Mid C) price forecasts for the 2013 IRP, 2011 IRP Update, and 2011 IRP.

[62] IPM® contains over 75 coal supply curves, with reserve estimates, by rank and quality. Coal supply curves are matched to coal demand areas, including transportation costs, and optimized. As such, IPM® is able to capture coal price response from incremental (decremental) demand, which ultimately affects the natural gas and emission prices that feed into System Optimizer and Planning and Risk.

[63] Emission modeling capabilities of IPM® were also used in this IRP to develop CO_2 prices for the two U.S. Hard Cap CO_2 price scenarios.

Figure 7.6 – Comparison of Base Henry Hub Gas Price Forecasts used for Recent IRPs

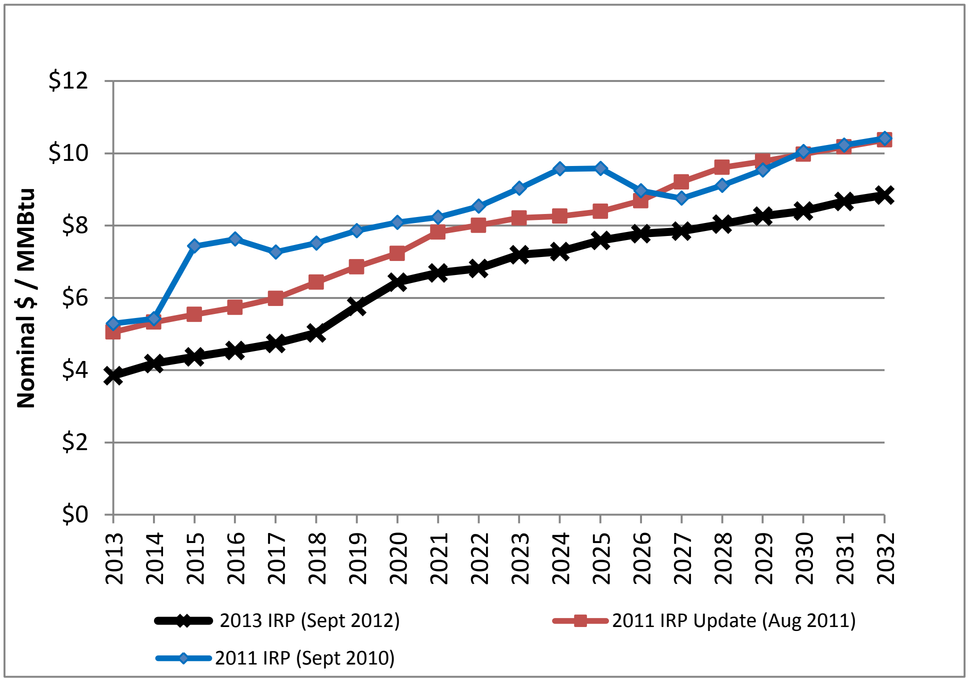


Figure 7.7 –Palo Verde Electricity Price Forecasts used in Recent IRPs

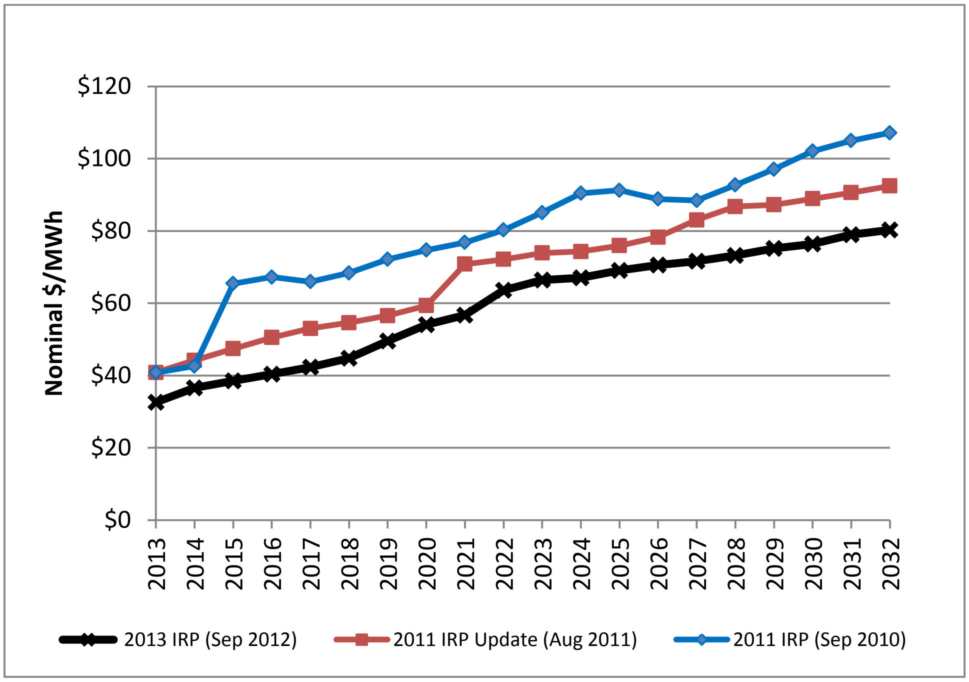
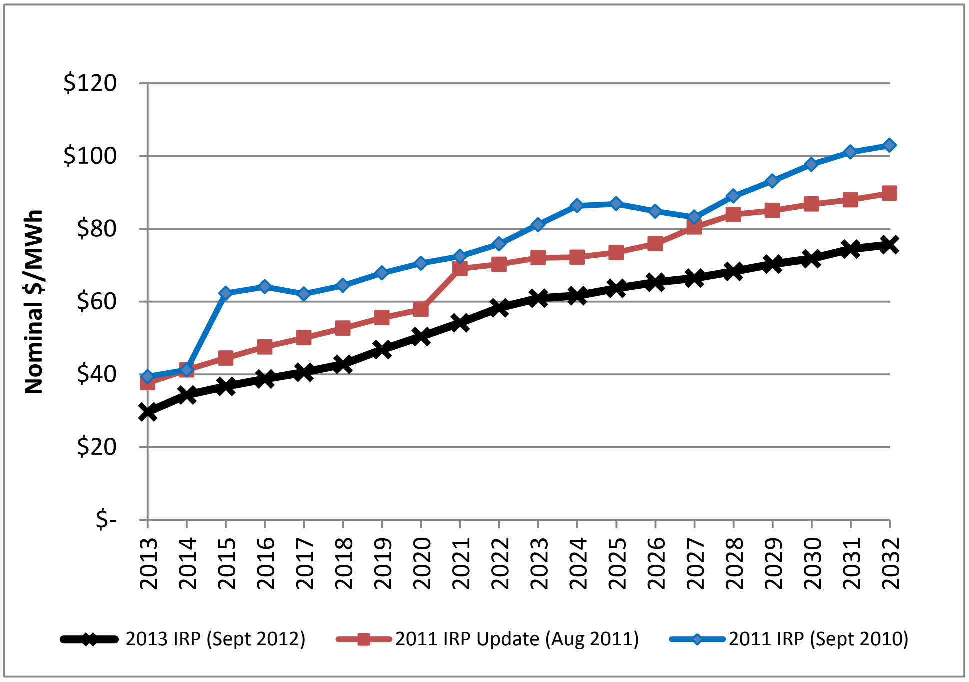


Figure 7.8 – Mid Columbia Electricity Price Forecasts used in Recent IRPs



Five natural gas price forecasts were used to derive the gas price projections for the 19 core cases analyzed in this IRP. A range of fundamental assumptions affecting how the North American market will balance supply and demand defines the underlying price forecasts.

The hard cap studies were developed June 2012. The supporting expert third-party high natural gas price scenario was issued May 2012 while the base price forecast reflects PacifiCorp's June 29, 2012 OFPC. The OFPC is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into an expert third-party fundamentals forecast, starting in month 85.

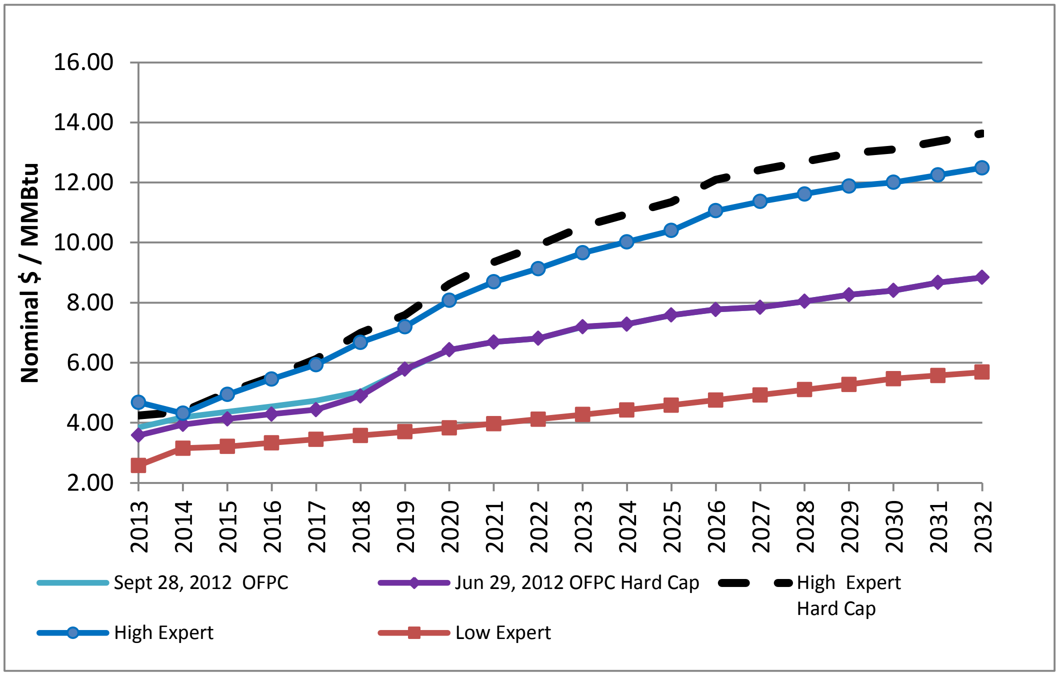
The CO_2 tax studies were developed September 2012. The supporting expert third-party high and low natural gas price scenarios were issued August 2012 while the base price forecast reflects PacifiCorp's September 2012 OFPC. Again, the OFPC is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into an expert third-party fundamentals forecast, starting in month 85.

Table 7.8 shows prices at the Henry Hub benchmark for the five underlying natural gas price forecasts. The forecasts serve as a point of reference and are adjusted to account for changes in natural gas demand driven by a range of environmental policy and technology assumptions specific to each IRP case. Figure 7.9 compares the five underlying Henry Hub price forecasts used in the 2013 IRP.

Table 7.8 – Underlying Henry Hub Natural Gas Price Forecast Summary (Nominal $/MMBtu)

Forecast Name	2013	2015	2020	2025	2032
High (Tax Scenario)	$4.68	$4.94	$8.07	$10.40	$12.49
Base (Tax Scenario)	$3.84	$4.37	$6.43	$7.59	$8.84
Low (Tax Scenario)	$2.58	$3.21	$3.83	$4.59	$5.68
High (Hard Cap Scenario)	$4.24	$5.01	$8.61	$11.35	$13.63
Base (Hard Cap Scenario)	$3.58	$4.13	$6.43	$7.59	$8.84

Figure 7.9 – Underlying Henry Hub Natural Gas Price Forecast Summary (Nominal $/MMBtu)



Price Projections Tied to the High Forecast

The driving assumption of the underlying high-price scenario is that of high oil prices. Outside of power generation, which was quick to respond to lower gas prices in 2012, the bulk of new demands will come later in the decade as liquefied natural gas (LNG) export facilities come online. Currently, the Cheniere Sabin Pass LNG export terminal is expected to be online in 2015 with other export terminals awaiting approval from the Federal Energy Regulatory Commission (FERC). Asian buyers are particularly attracted to Gulf Coast and East Coast export facilities since the LNG is more likely to be indexed to the price of Henry Hub (versus oil). Increased industrial demands are also expected to materialize later in the decade from the petrochemical, fertilizer, steel, and transportation sectors. Volumes expected to move into the transportation sector are particularly significant and will exert upward price pressure in the early 2020's. Moreover, the underlying high price scenarios assume that global shale development will be lagging. The lagging of global shale development helps keep natural gas pegged to oil prices (abroad) which, in turn, provides support to the US LNG export industry. Figure 7.10 summarizes prices at the Henry Hub benchmark and Figure 7.11 summarizes the accompanying electricity prices for the forecasts developed around the high gas price projection.

Figure 7.10 – Henry Hub Natural Gas Prices Derived from the High Underlying Forecast

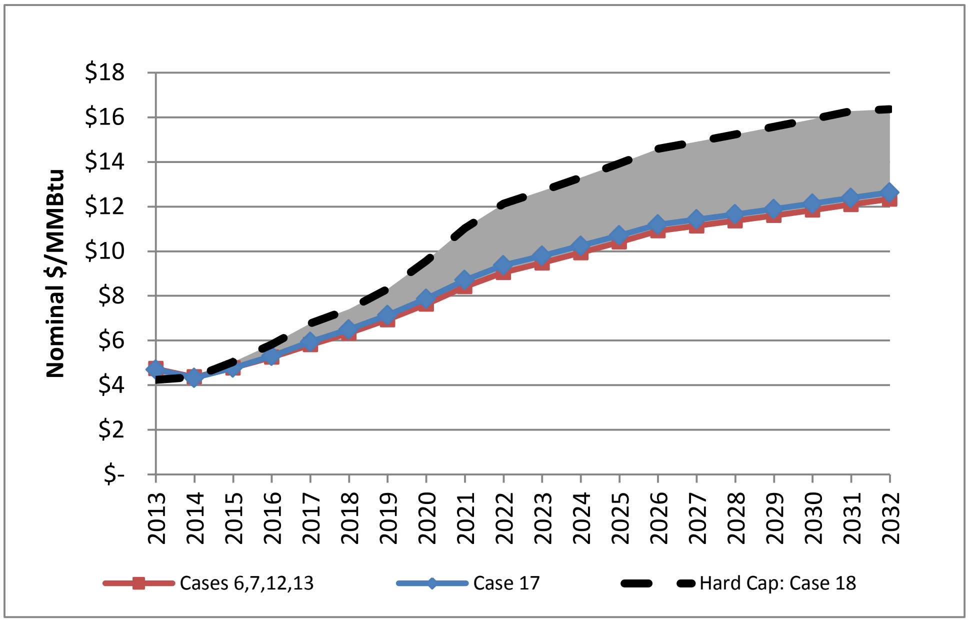
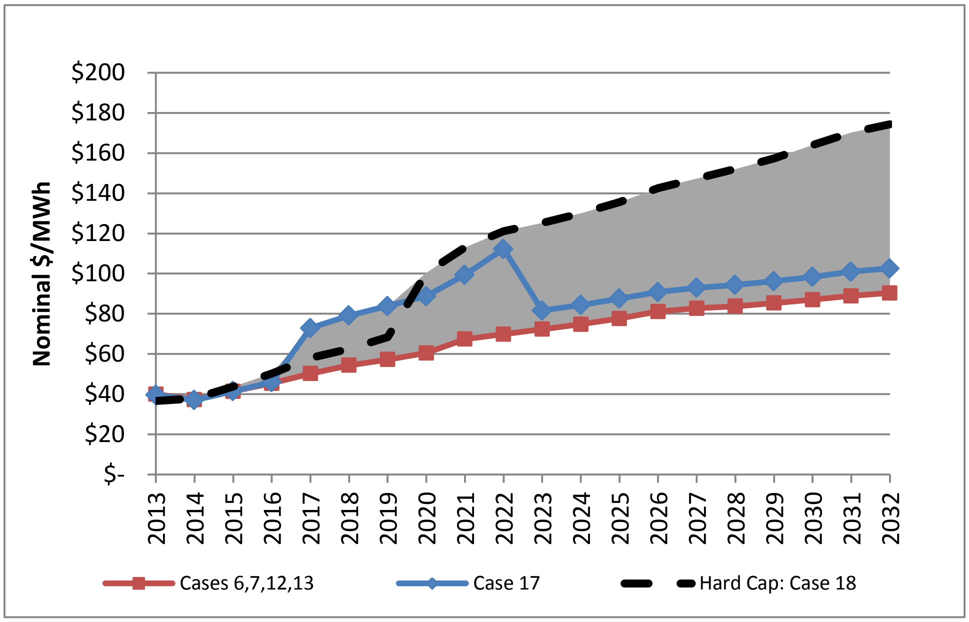


Figure 7.11 – Western Electricity Prices from the High Underlying Gas Price Forecast



Price Projections Tied to the Medium Forecast

The underlying September 2012 medium gas price forecast is also PacifiCorp's OFPC and, as such, is composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition into an expert third-party fundamentals forecast, starting in month 85. The expert third-party fundamentals forecast component was issued May 2012. The market portion of the forecast is based upon forwards as of market close September 28, 2012.

The medium gas scenario reflects a strong, but tempered, long-term demand for natural gas partially offset by increasing supply volumes resulting from new shale plays, increased well productivity, and rig efficiencies. While associated gas, from wet plays, has filled a large part of the void left by re-directed dry gas drilling, volumes are beginning to decline. To incent new dry gas drilling, prices will need to rise.

On the demand side, increased industrial loads are expected to materialize later in the decade from the petrochemical, fertilizer, steel, and transportation sectors. Like the high case, long-term demand increases are expected from the LNG export and transportation sectors however at a slower pace due to the lengthy approval process. Environmental restrictions on shale plays are expected to increase costs but not to the point of disrupting or adversely impacting supply. In short, the medium scenario assumes the continuance of prolific liquids plays producing significant amounts of price insensitive associated gas. However, going forward, quantities of associated gas cannot fully compensate for the lack of dry gas production. Thus, upward price pressure is forthcoming as decreased associated gas supply, coupled with increasing demands from the industrial, export, and transportation sectors, take hold later this decade. Figure 7.12 shows Henry Hub benchmark prices and Figure 7.13 includes the accompanying electricity prices for the forecasts developed around the medium gas price projection.

Figure 7.12– Henry Hub Natural Gas Prices Derived from the Medium Underlying Forecast

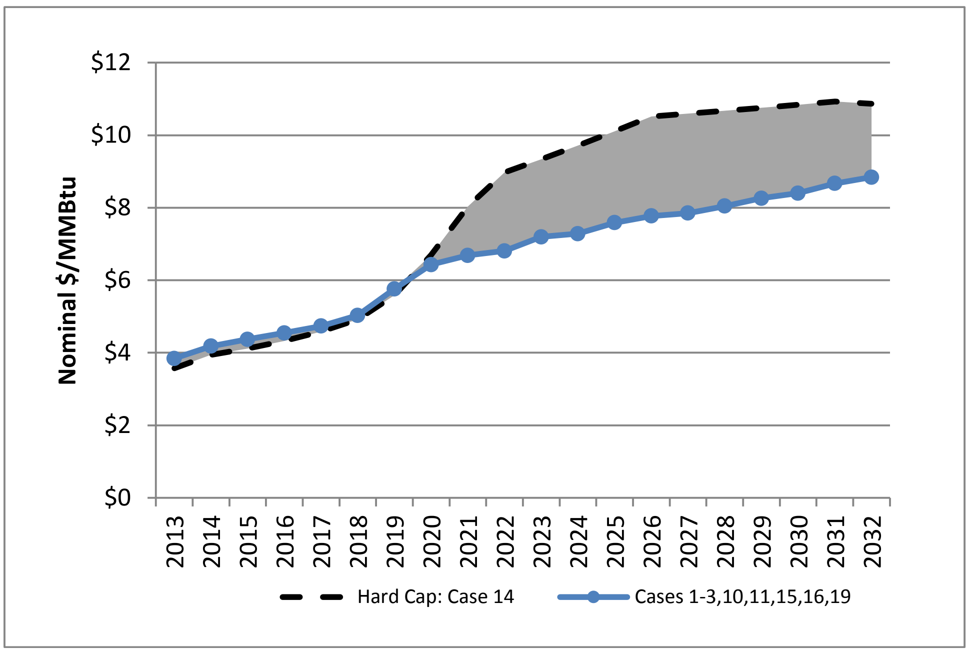
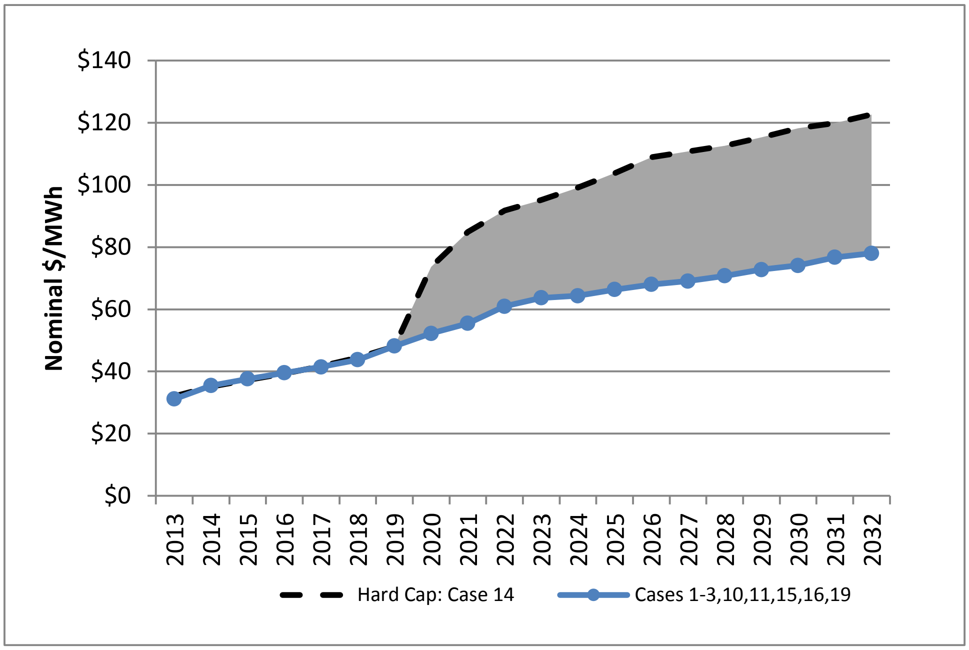


Figure 7.13 – Western Electricity Prices from the Medium Underlying Gas Price Forecast



Price Projections Tied to the Low Forecast

The low price is driven by excess gas supply and dampened demand (arising from moderated oil prices). On the supply side, increasing well productivity, technological innovations, and large volumes of price-insensitive associated gas create a flattened supply curve. Third party providers have reduced low price projections as base case forecasts have fallen to reflect continued improvements in well productivity and the large amount of price insensitive dry gas being produced as a byproduct in wet gas and shale oil plays. Even today, one-third of associated dry gas is being flared in the Bakken oil shale fields.

Under the low price assumptions, demand is tempered by limited natural gas use in both the transportation and LNG export sectors; no LNG export growth is assumed post 2020. Under this scenario, there is little incentive to invest in LNG export facilities or in gas-for-oil substitution in the transportation sector due to moderated oil prices. Moderate oil prices are attributed to the surge of U.S. shale liquids coming online. This is in keeping with expectations from both Exxon Mobile and the Energy Information Administration (EIA). Exxon Mobile's latest outlook expects the U.S. to be a net energy exporter by 2025 while the EIA expects U.S. gas production to outpace demand by 2020[64]. By 2030, the low price scenario assumes that over 19 million barrels per day (MMB/D) will be forthcoming from U. S. shale liquids, more than double that assumed in the high price scenario. Figure 7.14 shows Henry Hub benchmark prices and Figure 7.15 includes the accompanying electricity prices for cases built on the low price forecast in the 2013 IRP.[65]

[64] Wall Street Journal, *Exxon Find: America as Net Energy Exporter*, December 11, 2012, page B1.
[65] All case definitions that assume low natural gas prices also assume high CO_2 price assumptions.

Figure 7.14– Henry Hub Natural Gas Prices from the Low Underlying Forecast

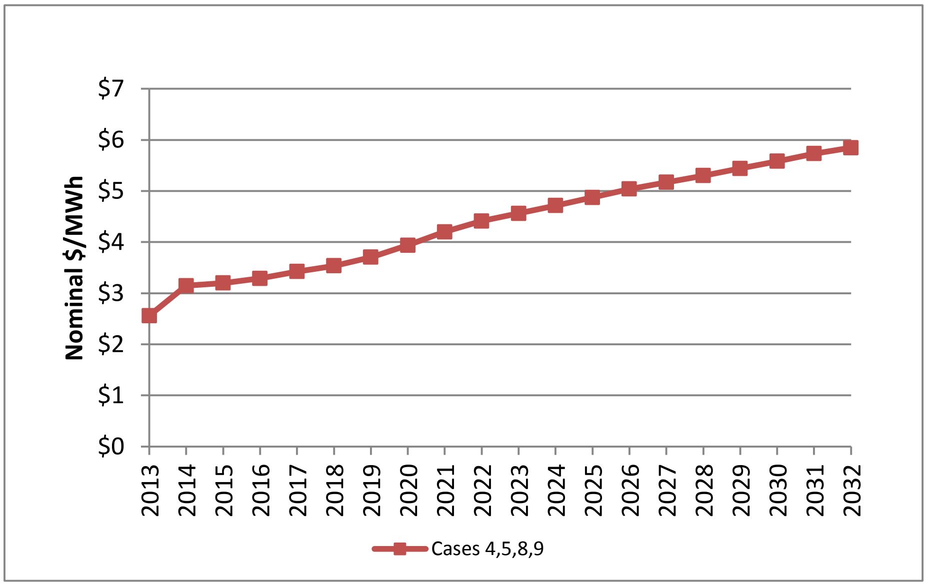
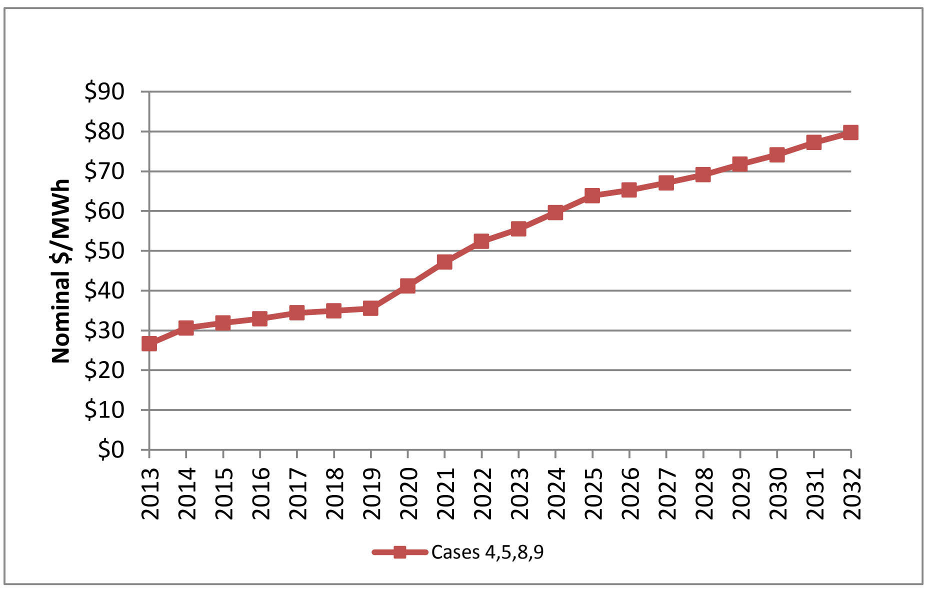


Figure 7.15 – Western Electricity Prices Derived from the Low Underlying Gas Price Forecast



Phase (3) Optimized Portfolio Development: No RPS Cases

For Phase 3 of the IRP modeling, System Optimizer is executed for each set of cases that exclude RPS requirements. These cases are completed for each of the five Energy Gateway scenarios, generating an optimized investment plan and associated real levelized PVRR for 2013 through 2032. System Optimizer simulations were first completed for these cases to identify potential renewable resources that are cost effective on a system basis. Cost effective renewable resource selections are then used to inform the next two phases of the IRP modeling process, as discussed in more detail in the following sections of this chapter.

Phase (4) Establishing a Renewable Resource Floor

For case definitions that include RPS assumptions, a minimum level of new renewable resources are needed to ensure that compliance can be achieved with specific state and/or assumed federal RPS requirements. This is achieved using an RPS compliance tool called the RPS Scenario Maker model. The RPS Scenario Maker model was introduced to the 2013 IRP modeling process in response to changing policy and market drivers that have effectively lowered the cost effectiveness of new renewable resource alternatives. These policy and market drivers are summarized below:

- Policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise making the long-term outlook for federal tax incentives that have traditionally benefited new renewable resources uncertain. Absent tax incentives, the cost for renewable resources per unit of energy output increases.
- Policy makers have not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not established a definitive schedule to propose rules applicable to existing sources. With continued uncertainty in federal greenhouse gas policy, the advantages of zero emission generation resources are diminished as compared to other resource alternatives.
- Over the past two years, reduced regional loads and low natural gas prices have contributed to reduced wholesale power prices. Reduced wholesale power prices lowers the energy value of generation from new renewable resources.

Given the drivers outlined above, the economic benefits of new renewable resources have deteriorated since the 2011 IRP was produced. In response, case definitions for the 2013 IRP were strategically designed to include cases that assume there are no RPS requirements to clearly identify whether new renewable resources are cost effective system resources or whether new renewable resources are needed for the sole purpose of meeting RPS requirements. To ensure that RPS compliance obligations are satisfied among those cases with RPS assumptions, the RPS Scenario Maker model was used to develop a renewable resource floor.

The RPS Scenario Maker model uses retail sales forecast inputs, state-specific targets, state-specific banked renewable energy credit (REC) balances, forecasted generation from existing RPS-eligible renewable resources, and cost and performance assumptions for potential new resources to optimize the type, timing, and location of additional renewable resources needed to meet future RPS compliance obligations. The RPS Scenario Maker model considers compliance flexibility mechanisms specific to any give RPS program including unbundled REC rules and banking rules that cannot be configured in the System Optimizer model to establish a least cost renewable resource mix that meets RPS requirements.

There are two steps in establishing the least cost RPS resource portfolio for each case that includes RPS assumptions. First, any renewable resources selected by the System Optimizer model among those cases that do not assume RPS requirements are automatically included in the RPS renewable resource portfolio for the accompanying case that does include RPS assumptions. These resources are treated as system resources for purposes of meeting state or assumed federal

RPS requirements, whereby each state is assumed to receive their proportionate share of energy that can be used for state-specific RPS compliance obligations. Second, the RPS Scenario Maker tool, configured with constraints to meet RPS targets and to accommodate state-specific RPS banking provisions, is used to provide an optimized low cost renewable resource portfolio that achieves any remaining state or federal RPS compliance shortfall with situs assigned renewable generation.[66]

Phase (5) Optimized Portfolio Development: RPS Cases

For Phase 5 of the IRP modeling, System Optimizer is executed for each set of cases that assume RPS requirements must be achieved. Each of these cases is completed for each of the five Energy Gateway scenarios, generating an optimized investment plan and associated real levelized PVRR for 2013 through 2032. The System Optimizer modeling process used in this phase of IRP modeling is identical to the System Optimizer modeling performed in Phase 3 (cases that exclude RPS assumptions) with the exception that a renewable resource floor that meets RPS compliance obligations is forced into the resource portfolio. Forcing the renewable resource floor into the System Optimizer resource expansion plan does not preclude the selection of additional renewable resources above and beyond the minimum threshold that is required to achieve RPS compliance.

Phase (6) Monte Carlo Production Cost Simulation

Phase 6 of the IRP modeling entails simulation of each optimized portfolio from Phases 3 and 5 using the PaR model in stochastic mode. The stochastic simulation produces a dispatch solution that accounts for chronological commitment and dispatch constraints. Three stochastic simulations were executed for three CO_2 tax levels: zero, medium (starting at $16/ton in 2022 and escalating to approximately $26/ton in 2032), and high (starting at approximately $14/ton and escalating to approximately $75/ton by 2032). All simulations used medium natural gas and wholesale power prices from the September 2012 OFPC as the expected gas and electricity price forecast values.

The PaR simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo random sampling of five stochastic variables: loads, commodity natural gas prices, wholesale power prices, hydro energy availability, and thermal unit availability for new resources. Availability of wind generation is not modeled with stochastic parameters in the PaR model; however, the incremental reserve requirements associated with uncertainty and variability in wind generation are captured in the stochastic simulation. PacifiCorp's wind integration study is included in Appendix H in Volume II of this report.

For stochastic analysis, PacifiCorp completed simulation of 37 portfolios produced by 18 core cases under Energy Gateway Scenario 1 and 19 core cases produced under Energy Gateway Scenario 2 using the PaR production cost model among three CO_2 price levels to yield 111 portfolio risk studies. The sensitivity cases developed for the 2013 IRP are informative in reporting the impact of isolated changes of inputs on the portfolio selection itself, and therefore, these cases were not studied in the PaR model.

[66] Given the relatively small size of the California RPS compliance need and no restrictions that limit the use of unbundled RECs, it is assumed that California RPS compliance obligations are met with unbundled REC purchases.

The Stochastic Model

The stochastic model used in the PaR model is a two-factor (short-run and long-run) short-run mean reverting model. Variable processes assume normality or log-normality as appropriate. Since prices and loads are bounded on the low side by zero they tend to take on a lognormal shape. Thus, prices, especially, are described as having a lognormal distribution (i.e. having a positively skewed distribution while their log_e has more of a normal distribution). Load growth is inherently more bounded on the upside than prices, and can therefore be modeled as having a normal or lognormal distribution. As such, prices and loads were treated as having a lognormal and normal distribution, respectively.

Separate volatility and correlation parameters are used for modeling the short-run and long-run factors. The short-run process defines seasonal effects on forward variables, while the long-run factor defines random structural effects on electricity and natural gas markets and retail load regions. The short-run process is designed to capture the seasonal patterns inherent in electricity and natural gas markets and seasonal pressures on electricity demand.

Mean reversion represents the speed at which a disturbed variable will return to its seasonal expectation. With respect to market prices, the long-run factor should be understood as an expected equilibrium, with the Monte Carlo draws defining a possible forward equilibrium state. In the case of regional electricity loads, the Monte Carlo draws define possible forward paths for electricity demand.

Stochastic Model Parameter Estimation

Stochastic model parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to “hover” around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. Consistent with the last IRP, PacifiCorp did not apply the long run load volatility parameter in this IRP.

Long-term volatility of natural gas and electricity prices is estimated using the standard error of a random walk regression of historic price data, by market. The resulting parameters are then used in the PaR model to develop alternative price scenarios around the Company’s official forward price curves, by market, over the twenty-year IRP study period. The long-run regression errors are correlated to capture inter-variable effects from changes to expected market equilibrium for natural gas and electricity markets, as well as the impacts from changes in expected regional electricity loads.

PacifiCorp's econometric analysis was performed for the following stochastic variables:

- Fuel prices (natural gas prices for the Company's western and eastern control areas)
- Electricity market prices for Mid-Columbia (Mid C), California – Oregon Border (COB) Four Corners, and Palo Verde (PV)
- Electric transmission area loads (California, Idaho, Oregon, Utah, Washington and Wyoming regions)
- Hydroelectric generation

Table 7.9 summarizes the 2013 IRP short-term load parameters, which were adopted from the 2008 IRP, as compared to the parameters used in the 2011 IRP. The 2008 IRP parameters were adopted having observed unreasonably large swings in loads using the 2011 IRP data. The Company anticipates re-estimating its short-term load parameters for its 2015 IRP. Natural gas and electricity price correlations by delivery point, as shown in Table 7.10, are the same as those developed for the 2007 IRP.

Table 7.9 – Short Term Load Stochastic Parameter Comparison, 2013 IRP vs. 2011 IRP

Short-term Volatility	Idaho	Utah	Washington	Oregon	Wyoming
Winter 2013 IRP	0.041	0.026	0.051	0.041	0.025
Spring 2013 IRP	0.051	0.028	0.038	0.032	0.022
Summer 2013 IRP	0.054	0.045	0.053	0.038	0.019
Fall 2013 IRP	0.046	0.036	0.040	0.043	0.019
Winter 2011 IRP	0.045	0.028	0.044	0.043	0.021
Spring 2011 IRP	0.038	0.037	0.043	0.044	0.017
Summer 2011 IRP	0.040	0.040	0.051	0.041	0.017
Fall 2011 IRP	0.040	0.036	0.046	0.042	0.019
Short-term Mean Reversion	**Idaho**	**Utah**	**Washington**	**Oregon**	**Wyoming**
Winter 2013 IRP	0.27	0.23	0.24	0.26	0.13
Spring 2013 IRP	0.05	0.09	0.19	0.16	0.10
Summer 2013 IRP	0.08	0.14	0.23	0.28	0.08
Fall 2013 IRP	0.23	0.17	0.20	0.18	0.10
Winter 2011 IRP	0.19	0.10	0.18	0.16	0.07
Spring 2011 IRP	0.02	0.16	0.24	0.21	0.10
Summer 2011 IRP	0.02	0.10	0.24	0.20	0.07
Fall 2011 IRP	0.03	0.08	0.11	0.11	0.05

Table 7.10 – Price Correlations

Winter						
	Nat Gas - East	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**	**Nat Gas - West**
Nat Gas - East	1.000	0.304	0.386	0.277	0.371	0.835
Four Corners	0.304	1.000	0.592	0.784	0.817	0.299
COB	0.386	0.592	1.000	0.634	0.564	0.492
Mid-Columbia	0.277	0.784	0.634	1.000	0.811	0.312
Palo Verde	0.371	0.817	0.564	0.811	1.000	0.364
Nat Gas - West	0.835	0.299	0.492	0.312	0.364	1.000

Spring						
	Nat Gas - East	Four Corners	COB	Mid-Columbia	Palo Verde	Nat Gas - West
Nat Gas - East	1.000	0.085	0.034	(0.131)	0.105	0.281
Four Corners	0.085	1.000	0.559	0.459	0.787	0.025
COB	0.034	0.559	1.000	0.770	0.468	0.067
Mid-Columbia	(0.131)	0.459	0.770	1.000	0.540	(0.059)
Palo Verde	0.105	0.787	0.468	0.540	1.000	(0.035)
Nat Gas - West	0.281	0.025	0.067	(0.059)	(0.035)	1.000

Summer						
	Nat Gas - East	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**	**Nat Gas - West**
Nat Gas - East	1.000	0.115	0.074	0.002	0.101	0.908
Four Corners	0.115	1.000	0.705	0.699	0.917	0.132
COB	0.074	0.705	1.000	0.809	0.734	0.117
Mid-Columbia	0.002	0.699	0.809	1.000	0.696	0.013
Palo Verde	0.101	0.917	0.734	0.696	1.000	0.126
Nat Gas - West	0.908	0.132	0.117	0.013	0.126	1.000

Fall						
	Nat Gas - East	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**	**Nat Gas - West**
Nat Gas - East	1.000	0.156	0.233	0.142	0.182	0.795
Four Corners	0.156	1.000	0.458	0.719	0.921	0.244
COB	0.233	0.458	1.000	0.446	0.467	0.299
Mid-Columbia	0.142	0.719	0.446	1.000	0.740	0.160
Palo Verde	0.182	0.921	0.467	0.740	1.000	0.281
Nat Gas - West	0.795	0.244	0.299	0.160	0.281	1.000

Table 7.11 lists short term volatility and mean reversion parameters for hydro generation that were re-estimated for the 2013 IRP based on updated historical hydro generation data, which covered calendar years 2003 through 2012.

Table 7.11 - Hydro Short Term Stochastic Parameter Comparison, 2011 IRP vs. 2013 IRP

	Short-term Volatility	Short-term Mean Reversion
2013 IRP	0.130	0.100
Winter 2011 IRP	0.0826	0.2901
Spring 2011 IRP	0.0739	0.2072
Summer 2011 IRP	0.0744	0.2263
Fall 2011 IRP	0.0901	0.2931

For outage modeling, PacifiCorp relies on the PaR model's Monte Carlo simulation method to create a distributed outage pattern for thermal resources. PacifiCorp does not estimate stochastic parameters for plant outages. Due to the true randomness of forced outages the Monte Carlo is the preferred mode of operation for obtaining results of multi-iteration Monte Carlo quality. While average historical and/or technology-specific outage rates are specified by the user the timing and duration of outages is random.

Monte Carlo Simulation

During model execution, the PaR model makes time-path-dependent Monte Carlo draws for each stochastic variable based on the input parameters. The Monte Carlo draws are of percentage deviations from the expected forward value of the variables, and are the same for each Monte Carlo simulation. In the case of natural gas prices, electricity prices, and regional loads, the PaR model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

The PaR model is configured to conduct 100 Monte Carlo iterations for the 20-year study period. For each of the 100 Monte Carlo iterations, the PaR model generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. Then, the model optimizes the dispatch of resources to minimize costs to serve load and wholesale sales obligations subject to operating and physical constraints, one of which is a fixed capacity expansion plan. The end result of the Monte Carlo simulation is 100 production cost iterations reflecting a wide range of portfolio cost outcomes.

For the 37 portfolios produced by the core case assumptions analyzed in Planning and Risk, the stochastic simulation utilizes medium electricity and natural gas price forecasts, regardless of the inputs used in the System Optimizer model to produce a given portfolio. Figures 7.16 through 7.19 show the 100-iteration frequencies for market prices resulting from the Monte Carlo draws for two representative years, 2013 and 2022, and by the east and west side of PacifiCorp's system. Figures 7.20 through 7.25 show annual loads by load areas and the system for the first, 10^{th}, 25^{th}, 50^{th}, 75^{th}, 90^{th}, and 99^{th} percentiles. Figure 7.26 shows the 25^{th}, 50^{th}, and 75^{th} percentiles for hydroelectric generation.

Figure 7.16 – Frequency of Western (Mid-Columbia) Electricity Market Prices for 2013 and 2022

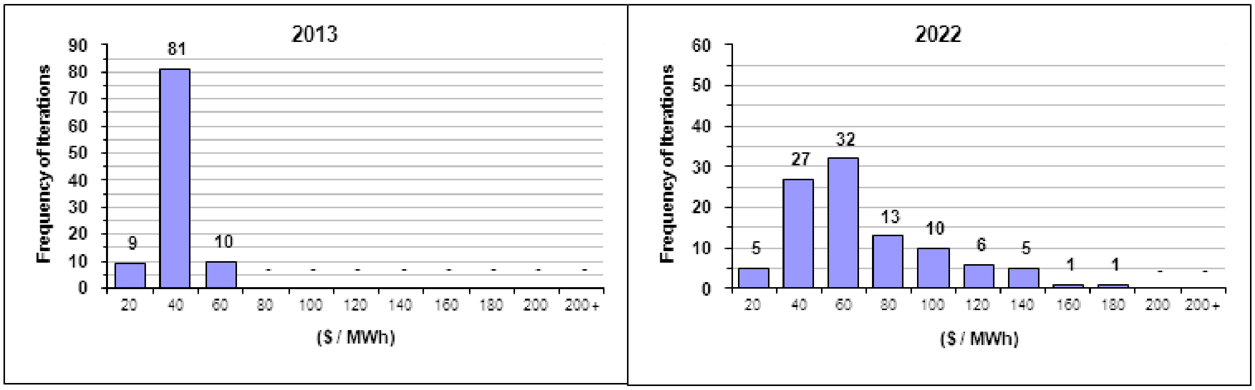


Figure 7.17 – Frequency of Eastern (Palo Verde) Electricity Market Prices, 2013 and 2022

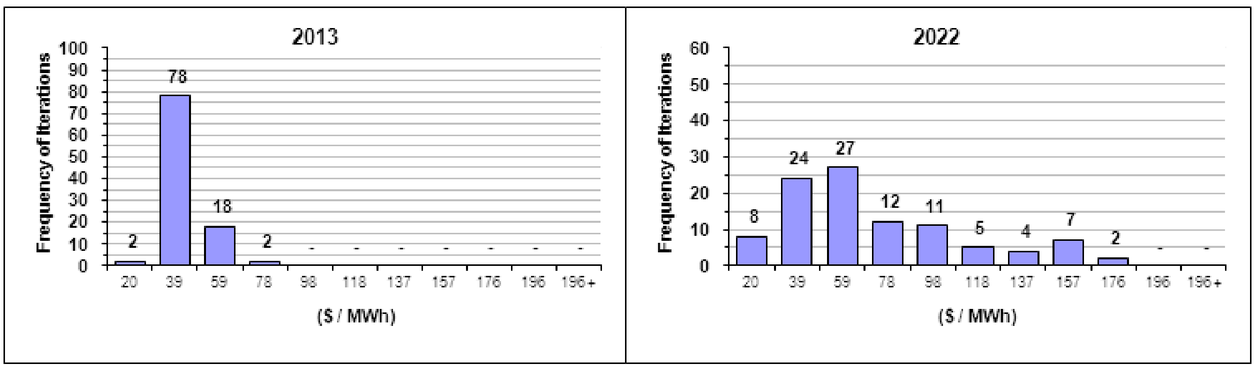


Figure 7.18 – Frequency of Western Natural Gas Market Prices, 2013 and 2022

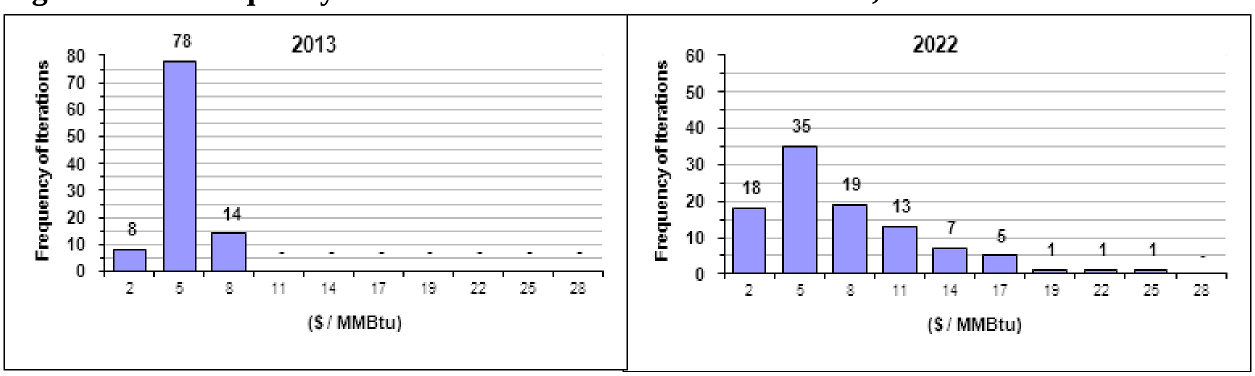


Figure 7.19 – Frequency of Eastern Natural Gas Market Prices, 2013 and 2022

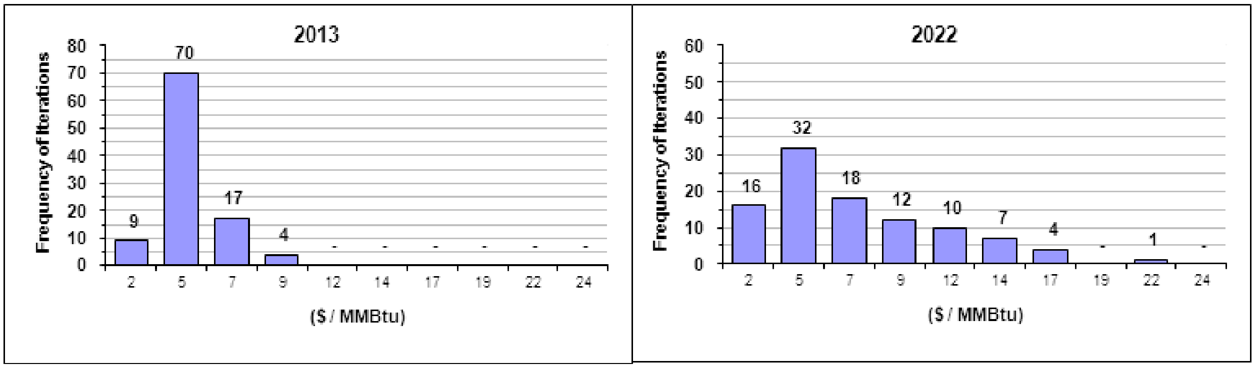
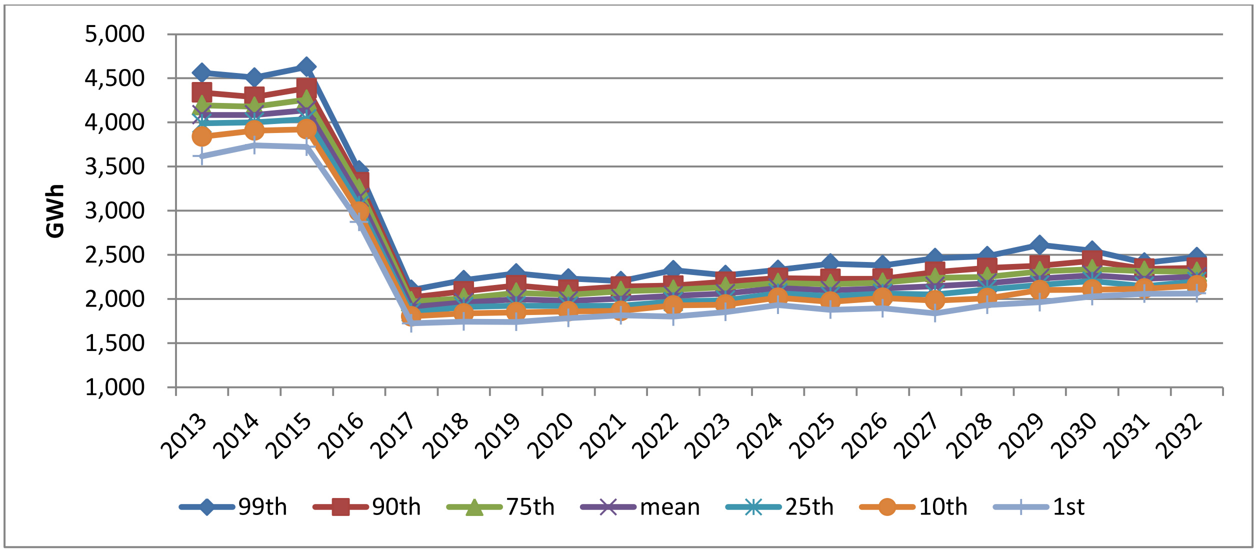


Figure 7.20 – Frequencies for Idaho (Goshen) Loads



Note: the drop in Idaho (Goshen) load from 2015 to 2017 is due to the expiration of a wholesale contract, under which PacifiCorp serves the retail load of the third party.

Figure 7.21 – Frequencies for Utah Loads

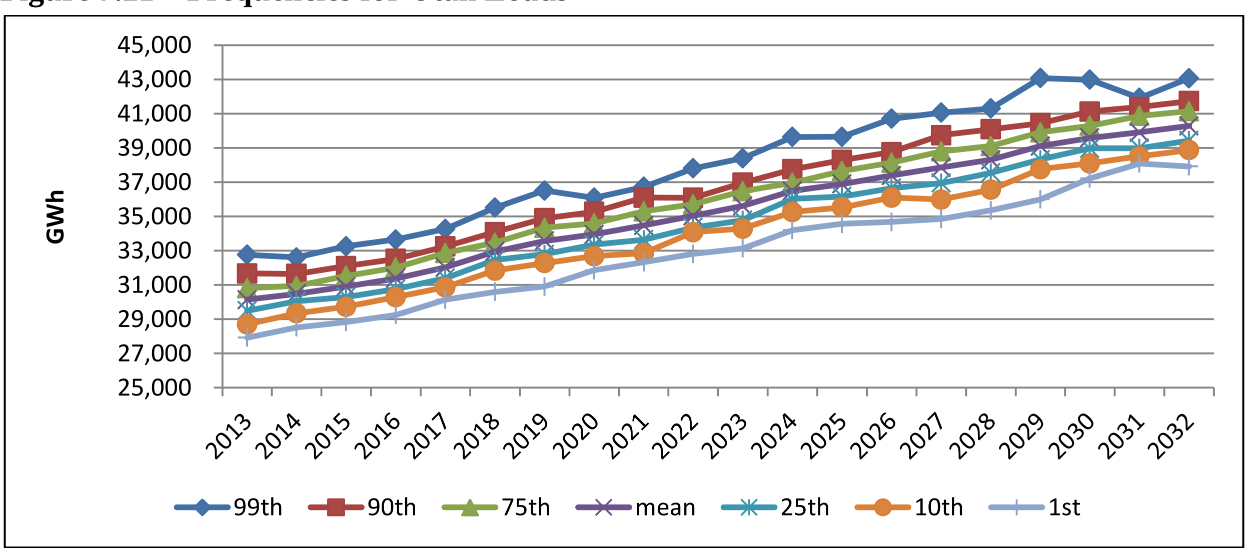


Figure 7.22 – Frequencies for Washington Loads

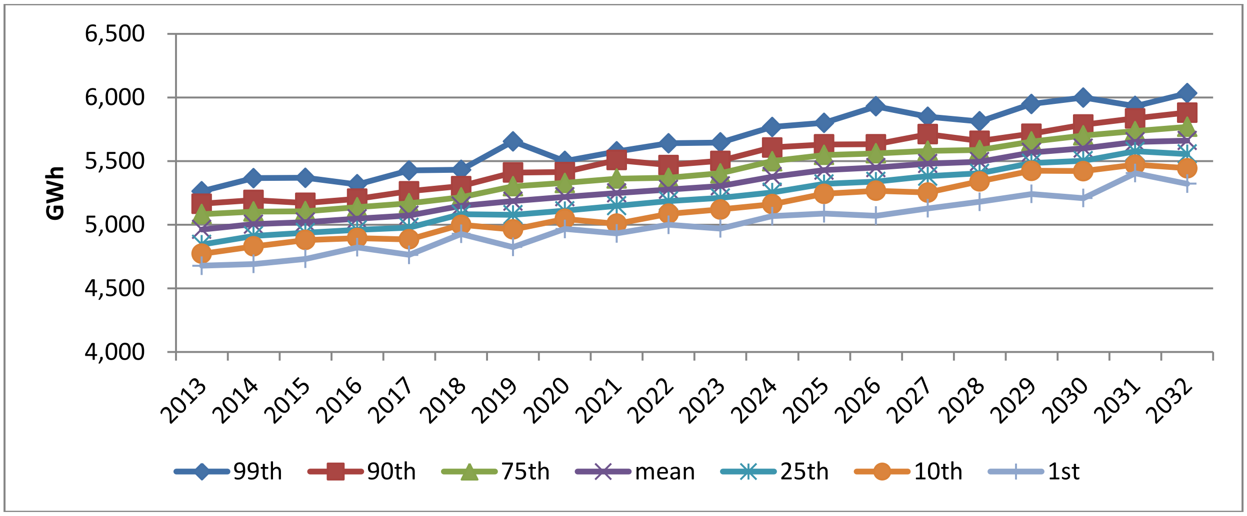


Figure 7.23 – Frequencies for California and Oregon Loads

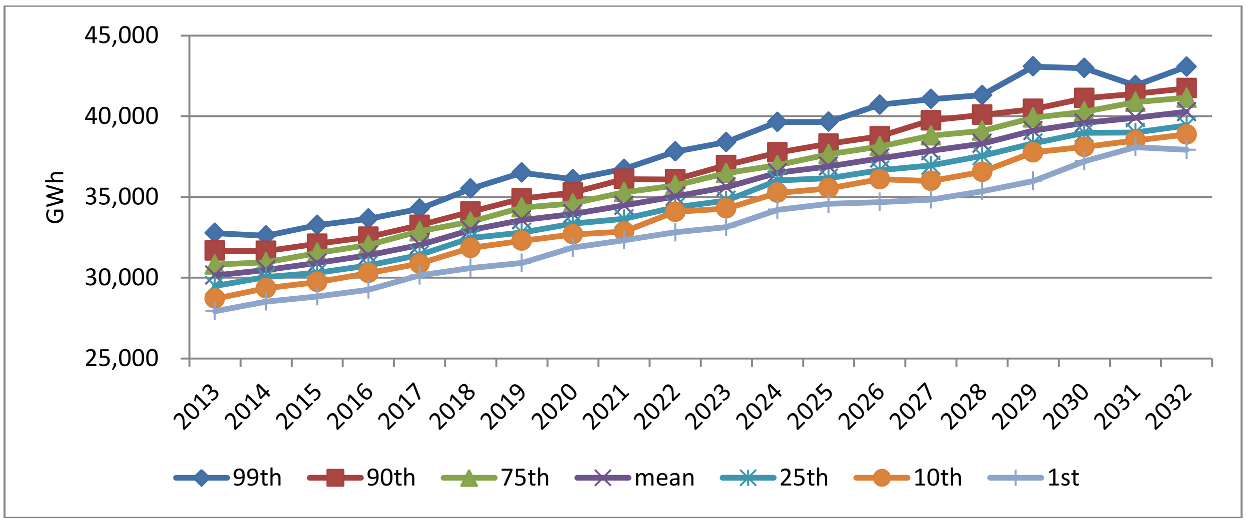


Figure 7.24 – Frequencies for Wyoming Loads

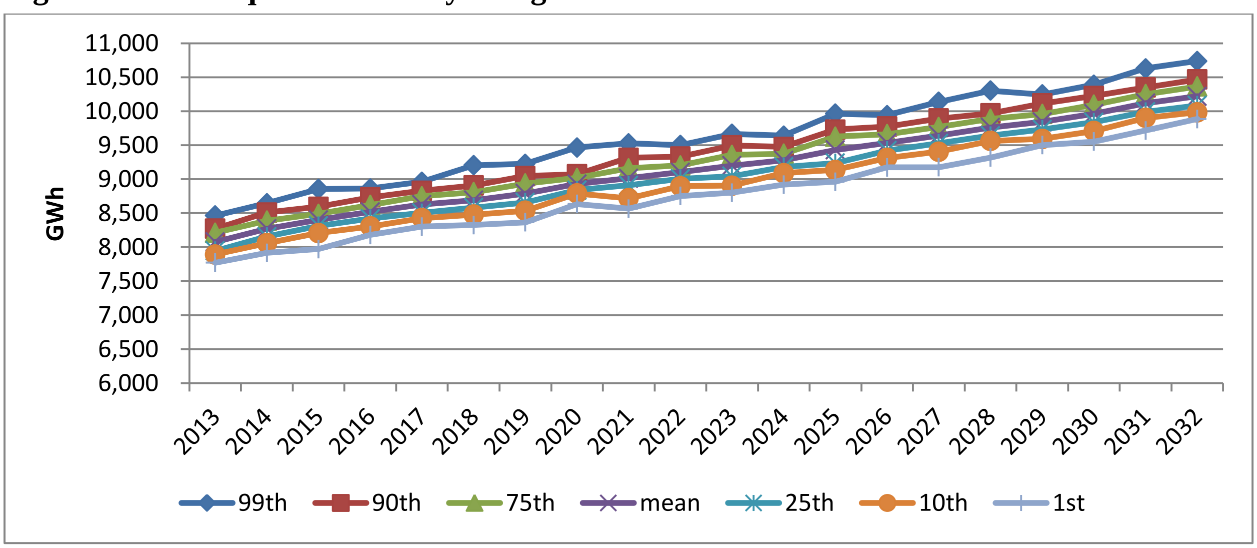


Figure 7.25 – Frequencies for System Loads

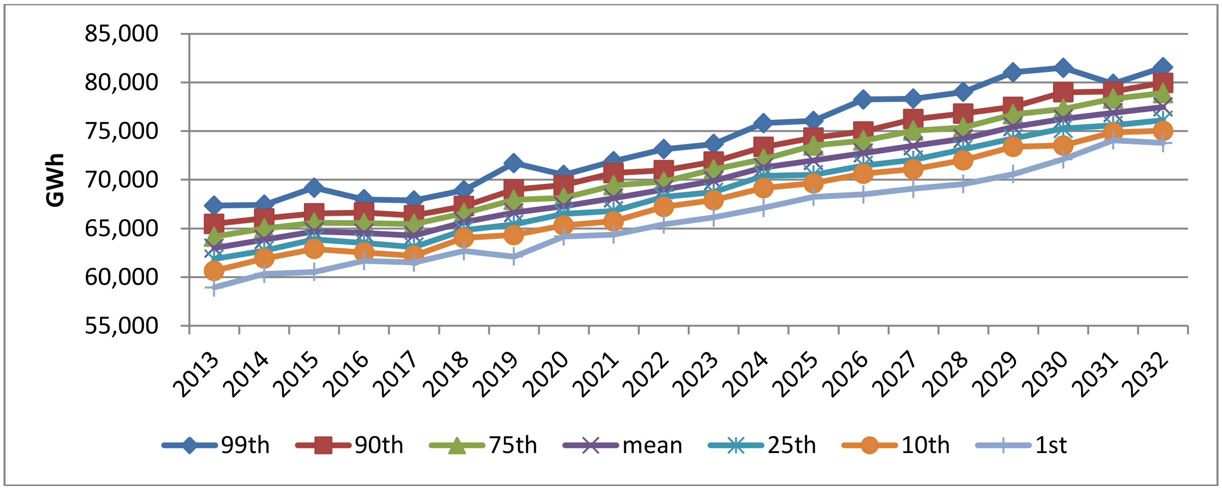
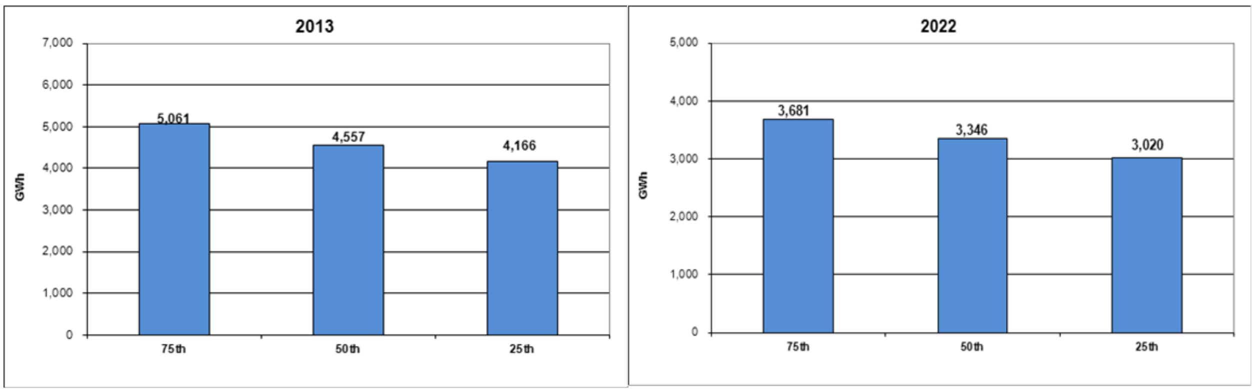


Figure 7.26 – Hydroelectric Generation Frequency, 2013 and 2022



The expected values of the Monte Carlo simulation are the average results of all 100 iterations. Results from subsets of the 100 iterations are also summarized to signify particularly adverse cost conditions, and to derive associated cost measures as indicators of high-end portfolio risk. These cost measures, and others are used to assess portfolio performance, and are described in the next section.

Stochastic Portfolio Performance Measures

Stochastic simulation results for the optimized portfolios are summarized and compared to determine which portfolios perform best according to a set of performance measures. These measures, grouped by category, include the following:

Cost

- Stochastic mean PVRR (Present Value of Revenue Requirement)
- Risk-adjusted mean PVRR
- 20-year customer rate impact

Risk

- Upper-tail Mean PVRR less stochastic mean PVRR
- 5th and 95th Percentile PVRR

Supply Reliability

- Average annual Energy Not Served (ENS)
- Upper-tail ENS

In addition to these stochastic measures, PacifiCorp also considers resource diversity and the CO_2 emissions when comparing portfolios.

The following sections describe in detail each of these performance measures as well as the fuel source diversity statistics.

Stochastic Mean PVRR

The stochastic mean PVRR for each portfolio is the average of the portfolio's net variable operating costs for 100 iterations of the PaR model in stochastic mode, combined with the real levelized capital costs and fixed costs determined by the System Optimizer model. The PVRR is reported in 2012 dollars.

The net variable cost from the stochastic simulations, expressed as a net present value, includes system costs for fuel, variable plant O&M, unit start-up, market contracts, spot market purchases and sales, and costs associated with making up for generation deficiencies, referred to as energy not served. The capital additions for new resources (both generation and transmission) are calculated on an escalated "real-levelized" basis to appropriately handle investment end effects. Other components in the stochastic mean PVRR include renewable PTCs, where applicable, and emission externality costs, such as costs associated with CO_2 emissions.

The PVRR measure captures the total resource cost for each portfolio, including externality costs in the form of CO_2 costs. Total resource cost includes all the costs to the utility and customer for the variable portion of total system operations, capital requirements and fixed costs as evaluated in this IRP.

Risk-adjusted Mean PVRR

Unlike a simple mean PVRR, the risk-adjusted PVRR also incorporates the expected-value cost of low-probability, expensive outcomes.[67] This measure – risk-adjusted PVRR, for short – is calculated as the stochastic mean PVRR plus five percent of the 95th percentile of the variable production cost PVRR, excluding fixed costs. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on the 100 Monte Carlo simulations conducted for each production cost run.

The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts without eliciting and applying subjective weights that express the utility of trading one cost attribute for another.

[67] Prices are assumed to take on a lognormal distribution for stochastic Monte Carlo sampling, since they are bounded on the low side by zero and are theoretically unbounded on the up side, exhibiting a skewed distribution.

Ten-year Customer Rate Impact
To derive the rate impact measures, the Company computes the percentage revenue requirement increase (annual and cumulative 10-year basis) attributable to the resource portfolio relative to a baseline full revenue requirements forecast. The year-on-year percentage change in revenue requirement is then calculated for each of the portfolios.

The IRP portfolio revenue requirement is based on the stochastic production cost results and capital costs reported for the portfolio by the System Optimizer model on real levelized basis and adjusted to nominal dollars based on the timing when new resources are selected and added to the portfolio, including investment in transmission resources.

While this approach provides a reasonable representation of projected total system revenue requirements for IRP portfolio comparison purposes, it is not intended as an accurate depiction of such revenue requirements for rate-making purposes. For example, the IRP revenue impacts assume immediate ratemaking treatment and make no distinction between current or proposed multi-jurisdictional allocation methodologies.

Upper-Tail Mean PVRR
The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the five highest production costs on a net present value basis. The portfolio's real levelized fixed costs are added to these five production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR
The 5th and 95th percentile stochastic PVRRs are also reported. These PVRR values correspond to the iteration out of the 100 that represents the 5th and 95th percentiles on the basis PVRR of production costs, respectively. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted PVRR measure. The 5th percentile PVRR is for informational purposes.

Production Cost Standard Deviation
To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost for the 100 Monte Carlo simulation iterations. The production cost is expressed as a net present value for the annual costs for 2013 through 2032. This measure is included because Oregon IRP guidelines require a stochastic measure that addresses the variability of costs in addition to one that measures the severity of bad outcomes.

Average and Upper-Tail Energy Not Served
Certain iterations of a stochastic simulation will have "energy not served" or ENS.[68] Energy Not Served is a condition where there are insufficient resources available to meet load because of physical constraints or market conditions. This occurs when the iteration has one or more stochastic variables with large random shocks that prevent the model from fully balancing the system for the simulated hour, such as large load shocks and simultaneous unplanned plant outages occur in the same iteration. Consequently, ENS, when averaged across all 100 iterations, serves as a measure of the stochastic reliability risk for a portfolio's resources.

[68] Also referred to as Expected Unserved Energy, or EUE.

For reporting of the ENS statistics, PacifiCorp calculates an average annual value for 2013 through 2032 in gigawatt-hours, as well as the upper-tail ENS (average of the five iterations with the highest ENS). Only the results using the medium CO_2 tax scenario are reported, as the tax level does not have a material influence on ENS amounts. In the current IRP, ENS is priced at $1,000/MWh consistent with a FERC imposed price cap.

Loss of Load Probability (LOLP)
Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the peak load during a given interval of time.

For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, only events that occur at the time of the regional peak are the ones likely to have significant consequences. Of those events, small shortfalls are likely to be resolved with a quick (though expensive) purchase. In Appendix L in Volume II of this report, the proportion of iterations with ENS events in July exceeding selected threshold levels are reported for each optimized portfolio simulated with the PaR model. The LOLP is reported as a study average as well as year-by-year results for an example threshold level of 25,000 MWh. This threshold methodology follows the lead of the Pacific Northwest Resource Adequacy Forum, which reports the probability of a "significant event" occurring in the winter season.

Fuel Source Diversity
For assessing fuel source diversity on a summary basis for each portfolio, PacifiCorp calculated the new resource generation shares for three resource categories as reflected in the System Optimizer expansion plan:

- Thermal
- Renewables
- Demand-side management

Phase (7) Top-Performing Portfolio Selection

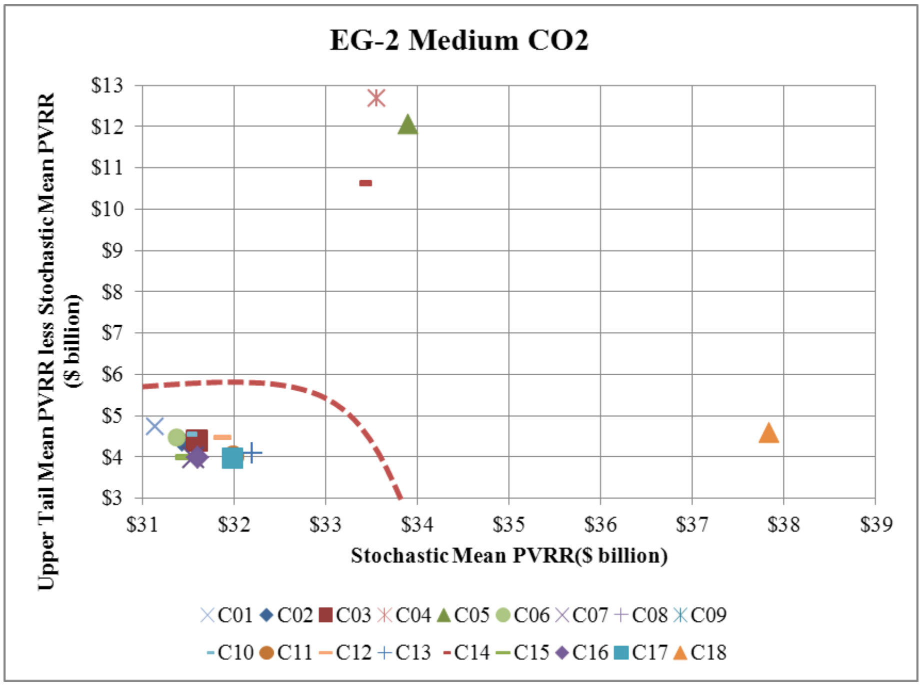
Initial Screening

As noted earlier, PacifiCorp conducted stochastic simulations of all core cases across two Energy Gateway scenarios and three CO_2 tax levels. For preferred portfolio selection, the Company reviewed stochastic performance metrics among those core cases developed under Energy Gateway Scenarios 1 and 2. Transmission lines in Energy Gateway Scenario 1 have either already been constructed or are currently under construction. Energy Gateway Scenario 2 includes preliminary analysis using the System Operational and Reliability Benefits Tool (SBT), described in Chapter 4, supports continued pursuit of Gateway Segment D. Portfolios developed under Energy Gateway Scenarios 3 through 5 were not analyzed as candidates for the preferred portfolio. Stochastic risk analysis of Energy Gateway segments included in these scenarios will be studied in future IRPs as the SBT, described in Chapter 4, is developed for each segment.

One of the cost measures in the screening of portfolios is the system PVRR. In order for the portfolios from different Energy Gateway scenarios to be comparable, the costs of the portfolios from Energy Gateway Scenario 2 are adjusted to reflect the benefits of Segment D as determined by the SBT that is discussed in Chapter 4.

Prior to the initial screening process, for each of the CO_2 price levels, a pre-screening was performed to remove outlier portfolios among the 36 portfolios whose mean PVRR and upper tail mean PVRR were clear cost and/or risk outliers in relation to other portfolios. Figure 7.27, which plots the upper tail risk and stochastic mean PVRR cost of candidate portfolios, illustrates how a clear delineation of cost and risk variance among portfolios can be used to exclude extreme outliers.

Figure 7.27 – Illustrative Pre-Screening to Remove Outliers



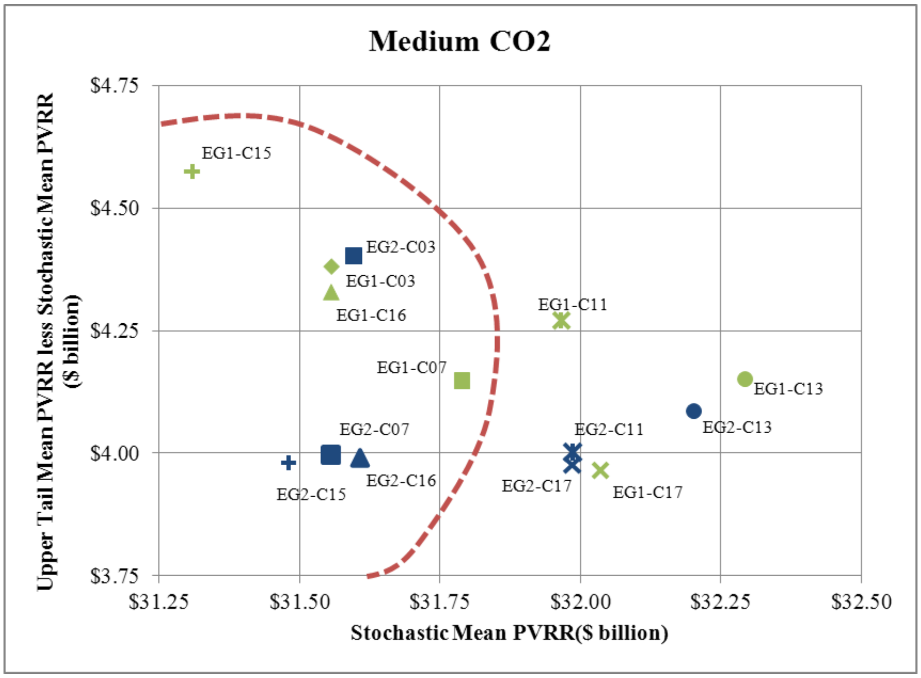
For the initial screening, PacifiCorp applied the following decision rule for identifying portfolios with the best combination of lowest mean PVRR and lowest upper-tail mean PVRR.

For each CO_2 tax scenario:

- Identify the portfolio with the lowest mean PVRR to establish a cost and risk threshold calculated as two percent of the least-cost portfolio;
- Identify portfolios that fall within the threshold amount as compared to the least cost portfolio;
- Identify portfolios that fall within the threshold amount as compared to the least risk portfolio, using the upper tail mean PVRR less the stochastic mean PVRR as the risk metric; then
- Select portfolios that fall within the least cost *and* least risk thresholds among any CO_2 price scenario as top performing portfolios.

The mean and upper-tail portfolio cost comparisons, as well as the top-performing portfolios, are shown graphically with the use of scatter-plot graphs. Figure 7.28 illustrates the application of the decision rule for the medium CO_2 tax scenario results, where the dashed red curve shows the demarcation separating the lowest cost least risk portfolios.

Figure 7.28 – Illustrative Stochastic Mean vs. Upper-tail Mean PVRR Scatter-plot



Final Screening

The optimal portfolios for the three CO_2 cost scenarios plus the cost averaging view are evaluated based on the following primary criteria and measures:

- Risk-adjusted PVRR
- Carbon dioxide emissions
- Supply reliability – average annual Energy Not Served and upper-tail mean (ENS)

Phase (8): Preliminary and Final Preferred Portfolio Selection

Selection of a preliminary preferred portfolio is based upon the Company's assessment of the criteria and measures used to summarize and rank candidate portfolios in the final screening analysis. In this phase, portfolio rankings are reviewed while considering deliverability and the core case definitions used to develop candidate portfolios. The Company also evaluates resource diversity among candidate portfolios, looking at both capacity and energy measures.

Final selection is made after performing additional analysis, as required, on the preliminary preferred portfolio taking into consideration conclusions drawn from analyses performed throughout the modeling process. For the 2013 IRP, the Company completed additional analysis on an alternative RPS compliance strategy that informed final section of the preferred portfolio

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Top performing portfolios developed from a range of core case definitions have consistently utilize front office transactions (FOTs) and demand side management programs to meet system capacity requirements in the first ten years of the planning periods.
- Portfolios with extensive coal retirements and coal unit gas conversions, occurring in cases defined by low natural gas prices and/or high carbon dioxide prices (CO_2), rely heavily on incremental gas resources, and are high cost and high risk as compared to portfolios that have no or limited coal retirements and coal unit gas conversions.
- In cases that do not have extensive coal retirements and coal unit gas conversions, most portfolios do not include incremental natural gas fired generation within the first ten years of the planning period. Beyond the Lake Side 2 project, which is currently under construction, the preferred portfolio does not show a need for a natural gas thermal resource until 2024.
- Cases defined without renewable portfolio standard (RPS) requirements produce portfolios that have limited utility-scale renewable resources, and cases defined with RPS requirements generally do not include incremental renewable resources beyond the minimum levels required achieve compliance with RPS targets.
- Inclusive of benefits calculated using the System Operational and Reliability Benefits Tool (SBT), top performing portfolios containing renewable resources that achieve compliance with RPS requirements perform better under Energy Gateway Scenario 2, which includes the Windstar-Populus project, when compared to portfolios developed under Energy Gateway Scenario 1.
- PacifiCorp's preferred portfolio includes the resources identified in the following table:

	Installed Capacity, MW																				
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Expansion Options																					
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	**2,054**	**1,606**	**1,509**	**1,640**	**1,648**	**1,639**	**1,685**	**1,281**	**1,500**	

Introduction

This chapter reports modeling and performance evaluation results for the portfolios developed with a broad range of input assumptions using the System Optimizer model and simulated with the Planning and Risk model. The preferred portfolio is presented along with a discussion of the relative advantages and risks associated with the top-performing portfolios.

Discussion of the portfolio evaluation results falls into the following two main sections.

- Preferred Portfolio Selection – This section covers: (1) core case portfolio results, (2) stochastic production cost modeling results for these portfolios, (3) portfolio screening results, (4) evaluation of the top-performing portfolios, and (5) preferred portfolio selection.
- Portfolio Sensitivity Analysis – This section covers development and a comparative analysis of sensitivity case portfolios to core case portfolios.

Preferred Portfolio Selection

Core Case Portfolio Results

The preferred portfolio selection process began with the development of resource portfolios using the System Optimizer model. There are 19 core cases under each of the Energy Gateway scenarios.[69] Figures 8.1 to 8.5 represent the cumulative capacity additions by resource type for each of the core case portfolios and under the five Energy Gateway scenarios during the study period of 2013 to 2032. The detailed resource portfolio tables are included in Appendix K, along with present value of revenue requirement (PVRR) results. Comparison of the resource portfolios supports the following observations:

- Through the 20 year planning period, resource portfolios have stable levels of front office transactions (FOTs) and demand side management (DSM) resources, indicating selection of these resource types are cost effective among a wide range of scenarios.

- Except for those scenarios with core case assumptions that yield extensive coal unit retirements and gas conversions, natural gas resource additions are stable and not required until the latter years of the planning horizon.

- Core case definitions with low natural gas prices and/or high CO_2 prices produced portfolios with large scale early coal unit retirements and natural gas conversions that create an increased capacity need largely satisfied with incremental gas resource additions.

- Over the 20-year planning horizon, resource selections, while not identical, are similar among the different Energy Gateway scenarios. The type and timing of new renewable resources among cases with renewable portfolio standard (RPS) assumptions are influenced by inclusion of Energy Gateway transmission, and are largely driven by increased access to high capacity

[69] Core case C-19, which assumes an alternative to Energy Gateway Segment D, was not analyzed under Energy Gateway Scenario 1, which does not include the Segment D project.

factor wind resources in Wyoming with the addition of the Windstar-Populus project, which is included in Energy Gateway Scenarios 2 through 5.

Figure 8.1 – Total Cumulative Capacity under Energy Gateway Scenario 1, 2013 through 2032

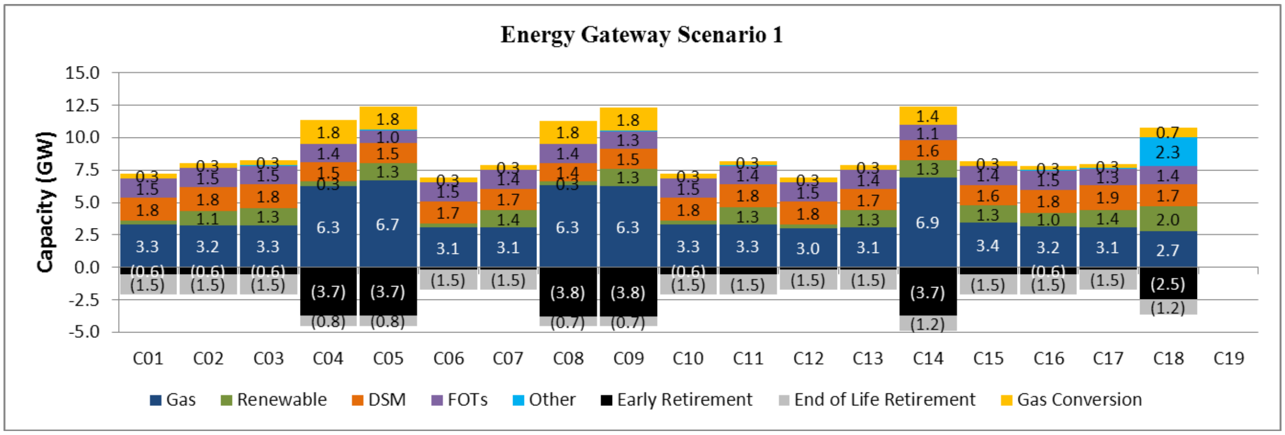


Figure 8.2 – Total Cumulative Capacity under Energy Gateway Scenario 2, 2013 through 2032

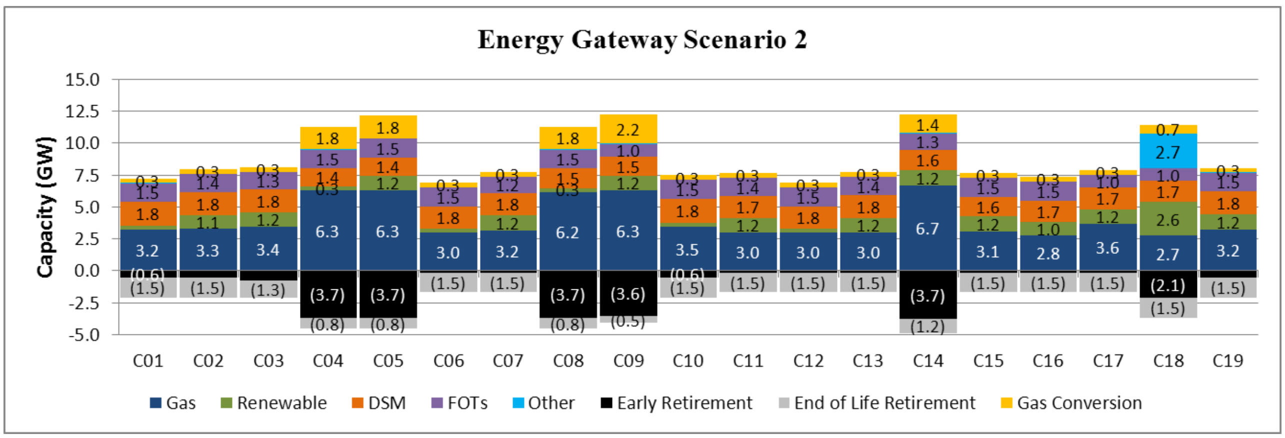


Figure 8.3 – Total Cumulative Capacity under Energy Gateway Scenario 3, 2013 through 2032

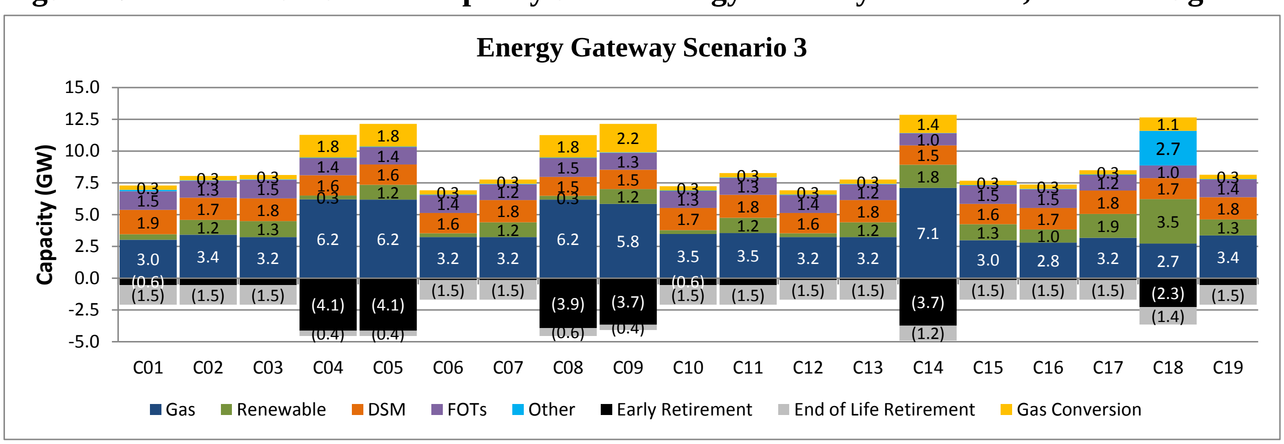


Figure 8.4 – Total Cumulative Capacity under Energy Gateway Scenario 4, 2013 through 2032

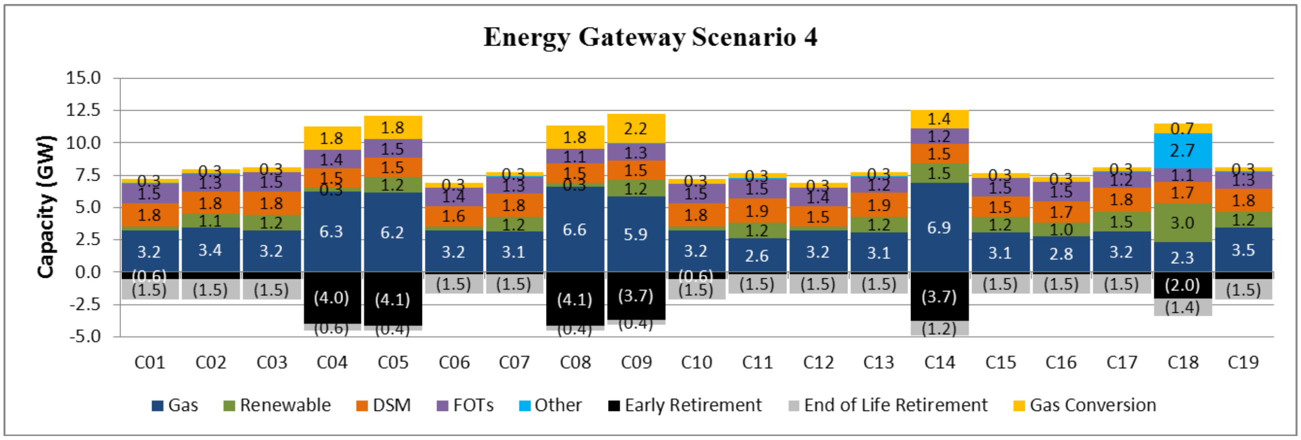
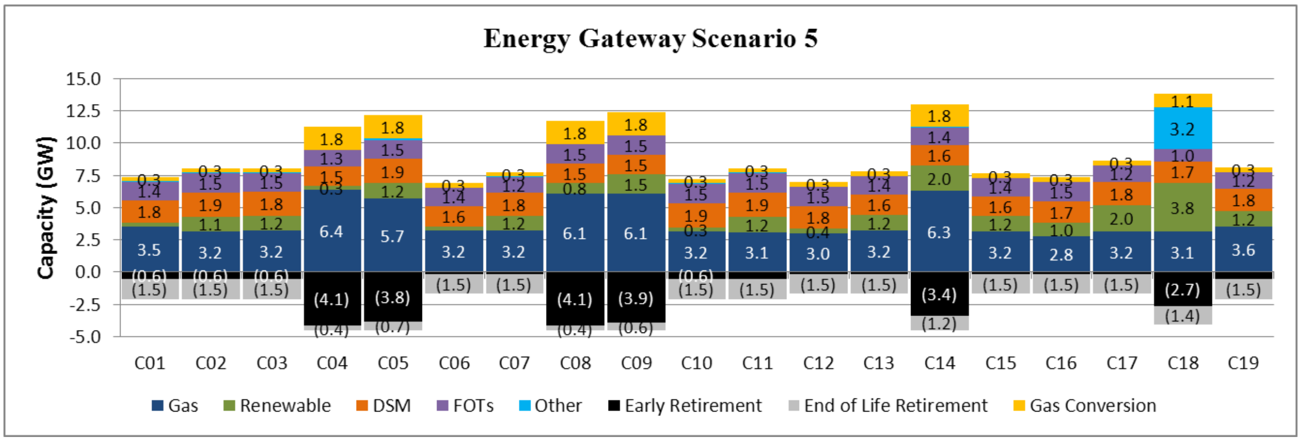


Figure 8.5 – Total Cumulative Capacity under Energy Gateway Scenarios 5, 2013 through 2032



Resource Selection by Resource Type

Gas Resources

- All portfolios include the Lake Side 2 combined cycle combustion turbine (CCCT) generating plant, which is currently under construction with a 2014 in-service date.
- There are no near-term gas-fired resources in cases defined with medium or high natural gas prices paired with medium or zero CO_2 price assumptions.
- Near-term natural gas resources are included in those portfolios where extensive coal unit retirements and natural gas conversions take place. This includes those cases with a combination of low natural gas prices, high CO_2 prices, and high coal costs (cases C04, C05, C08, and C09) and cases with U.S. hard cap CO2 price assumptions (cases C14 and C18).
- A 2017 CCCT is included in case C17, driven by an assumed market price spike that makes FOTs more expensive.
- Gas-fired resources, added primarily in the latter half of the planning horizon among most cases, include both CCCTs in both 2x1 and 1x1 configurations with duct firing capability, and simple cycle combustion turbines (SCCTs).

Renewable Resources

- Cases that do not assume RPS assumptions are generally devoid of incremental wind resources, indicating that new wind resource additions are not cost effective given deteriorating policy and market conditions.
- Cases defined with RPS requirements generally do not include incremental renewable resources beyond the minimum levels required to achieve compliance with RPS targets. An exception to this outcome is case C14, which assumed U.S. hard cap CO_2 prices that improve the cost effectiveness of new wind generation.
- Case C18, which assumes policy and market drivers favorable to renewable resource additions (high natural gas prices, high power prices, U.S. hard cap CO_2 prices, and extension of federal tax credits through 2019) includes between 1,100 and 2,900 megawatts (MW) of new wind resources, depending upon the Energy Gateway scenarios, 450 MW of large utility scale solar photovoltaic (PV) resources, and 135 MW of capacity through a geothermal PPA by the end of the planning horizon.
- Large scale utility solar PV resources located in Utah are added in cases with RPS requirements under Energy Gateway Scenario 1 and in all 18 cases. With the exception of case C18, wind resource additions displace large utility scale solar PV resources in meeting RPS obligations when the Windstar-Populus transmission project is included among Energy Gateway Scenarios 2 through 5.
- Geothermal resources were modeled as a power purchase agreement (PPA) in the 2013 IRP and are forced into C16 portfolios.
- All portfolios include approximately 15 MW of distributed solar resource additions each year totaling 290 MW over the 20 year planning horizon. These resources are largely driven by a Utah solar incentive program, currently scheduled to conclude in 2017. Through the 2017 period, it is assumed the program will achieve approved installation levels, and beyond 2017, these resources are selected by the System Optimizer model.

Demand-side Management

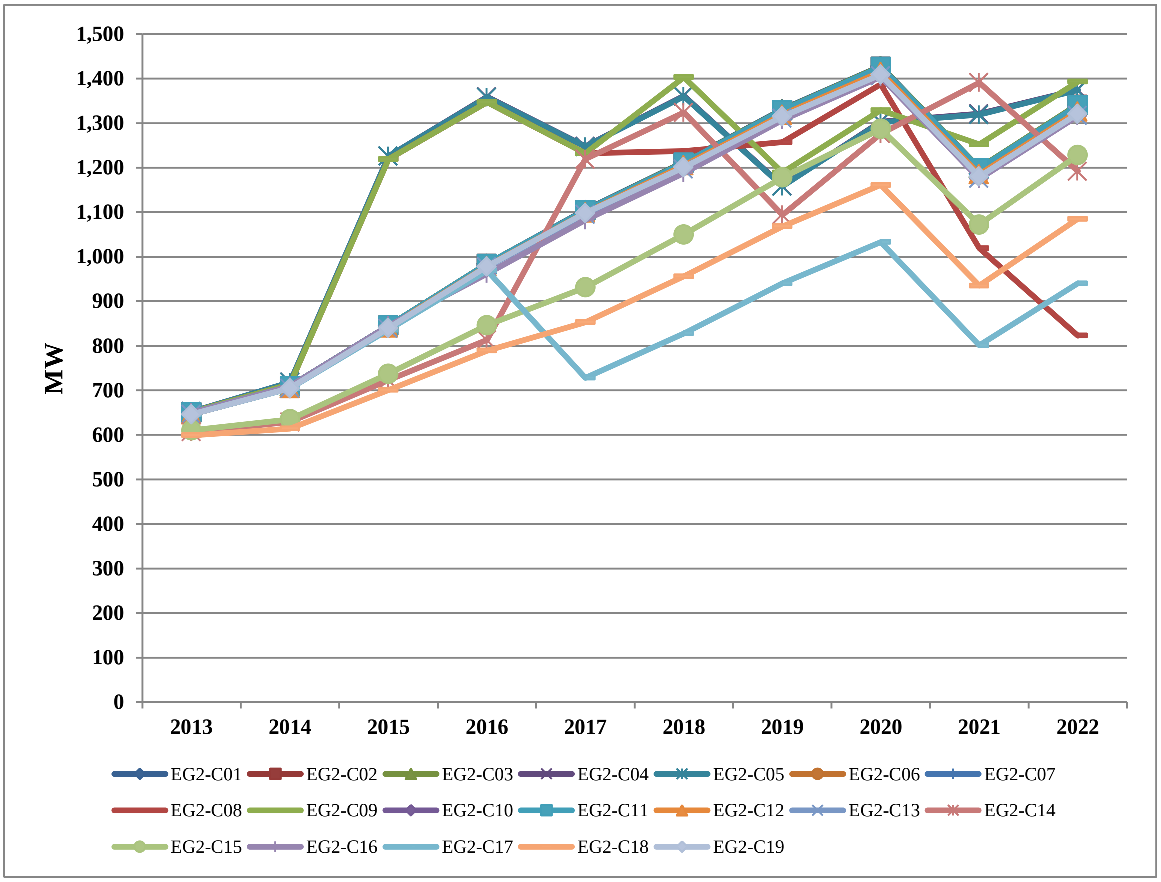
- Energy efficiency (Class 2 DSM) resource additions are prevalent among all portfolios and play a significant role in meeting projected capacity and energy needs through the planning horizon.
- Energy efficiency additions occur steadily throughout the simulation period, and by 2032 range between approximately 1,400 MW and 1,900 MW among portfolios in each Energy Gateway Scenario.[70]
- In cases where accelerated acquisition of energy efficiency resources is assumed to be achievable (cases C14, C15, and C18), energy efficiency resources displace FOT resources in the near-term; however, over the long-term, these cases do not yield incremental energy efficiency resources as compared to other portfolios.
- Dispatchable load control programs (Class 1 DSM) are not added to resource portfolios in Energy Gateway Scenario 1 until 2020 and not until 2023 in Energy Gateway Scenarios 2 through 5. In cases with extensive coal unit retirements and natural gas conversions, little to no Class 1 DSM resources are included in the resource mix. On average, among all core case portfolios, System Optimizer selected between 123 MW of Class 1 DSM resources by 2032.

[70] These figures are analogous to a "nameplate" rating for thermal resources, and represent the maximum amount of load reduction savings expected for a given year.

Front Office Transactions

- All portfolios utilized front office transactions to fill both near-term and long-term system capacity needs, a consistent trend among all Energy Gateway scenarios. Figure 8.6 shows the annual front office transactions selected among core case portfolios under Energy Gateway Scenario 2. Over the first 10 years of the planning period, FOTs range between 599 MW and 1,428 MW. In the latter half of the planning horizon, annual FOT resource selections range between 710 MW and 1,472 MW. Beyond 2016, selection of FOTs is highest in case C17, which assumes a market price spike through 2022. Prior to 2016, FOTs are highest in cases with near-term coal unit retirements (cases C04, C05, C08 and C09).

Figure 8.6 – Front Office Transaction Addition Trends by Portfolio, EG-2



Retirements/Gas Conversion of Existing Coal-Fired Resources

- All portfolios reflected the end of life retirement of Carbon Unit 1 and Unit 2 in 2015.
- In addition to Carbon Unit 1 and Unit 2, asset lives of nine coal-fired facilities are assume to end prior to the end of this IRP's study period.
- All portfolios reflect the conversion of Naughton Unit 3 to natural gas.
- Portfolio selections show that in the cases defined with medium or high natural gas prices and medium or low CO_2 prices, there are very few occurrences of coal unit early retirements or natural gas conversions. This is observed whether base case or stringent case Regional Haze investments are assumed.
- In the cases defined with high CO_2 price, low gas price and high coal cost assumptions (cases C04, C05, C08, and C09), the majority of the existing coal-fired facilities retire early and in the

first 10 years of the planning horizon. Among these cases, early retirement outcomes are not significantly different whether base case or stringent Regional Haze investments are assumed. In cases where U.S. hard cap CO_2 price assumptions are made (cases C14 and C18) coal units retire early, but latter in the planning period as compared to cases C04, C05, C08, and C09.

Impact of Energy Gateway Segments

- Additional segments of the Energy Gateway reduce system costs, especially for cases assuming RPS requirements. In these cases, access to high capacity factor Wyoming wind resources made possible by the addition of the Windstar-Populus transmission line in Energy Gateway Scenarios 2 through 5, lower RPS compliance costs.
- Figures 8.7 through 8.10 show the increase in Energy Gateway transmission costs between different Energy Gateway Scenarios as compared to Energy Gateway Scenario 1 (red line) alongside changes in system PVRR costs, as calculated by System Optimizer, between like portfolios in different Energy Gateway Scenarios as compared to Energy Gateway Scenario 1 (bars). Differences in portfolio costs among like cases do not include the benefits of Segment D as determined by the System Operational and Reliability Benefits Tool (SBT) described in Volume I, Chapter 4. Bars that fall below the red line indicate portfolios observed system cost benefits when incremental Energy Gateway transmission is added. Core cases that include RPS assumptions show system cost benefits with incremental transmission investment. Core case C19 assumes there an alternative to Energy Gateway Segment D, and is not included under Energy Gateway Scenario 1. Consequently, case C19 is not shown in the figures below.

Figure 8.7 – PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 2 and Energy Gateway Scenario 1 (System Optimizer)

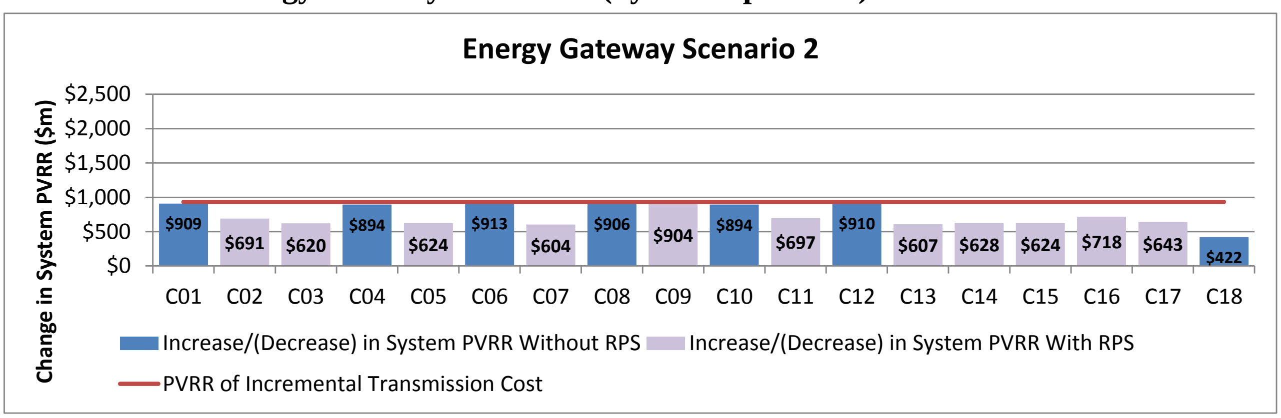


Figure 8.8– PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 3 and Energy Gateway Scenario 1 (System Optimizer)

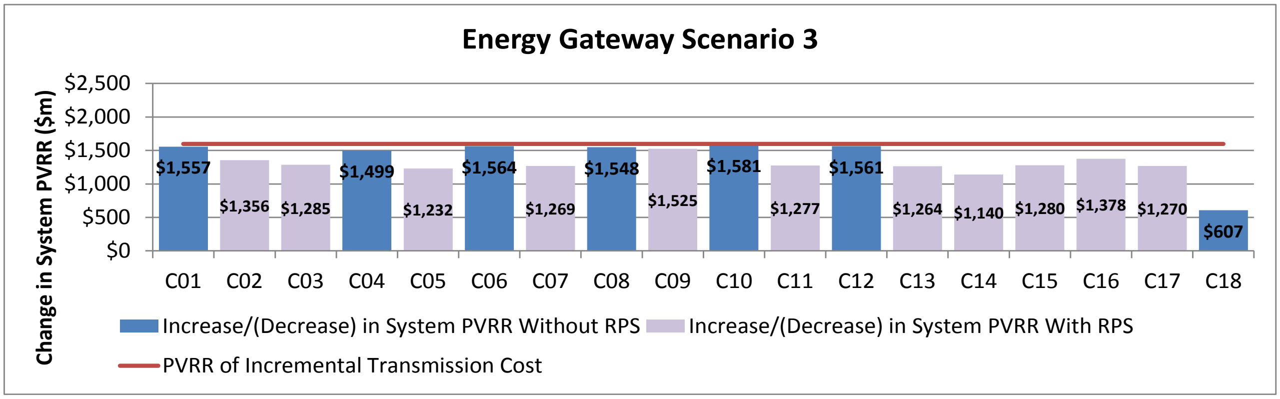


Figure 8.9 – PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 4 and Energy Gateway Scenario 1

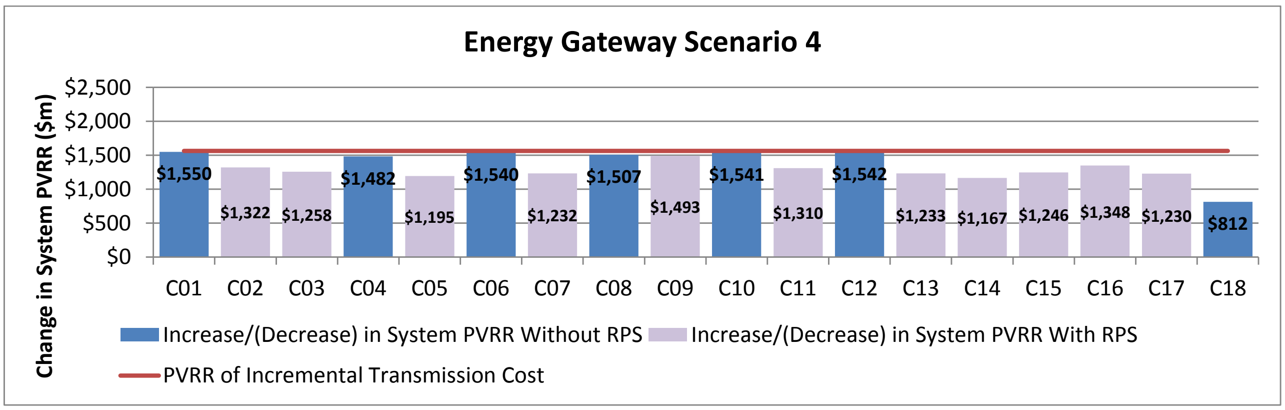
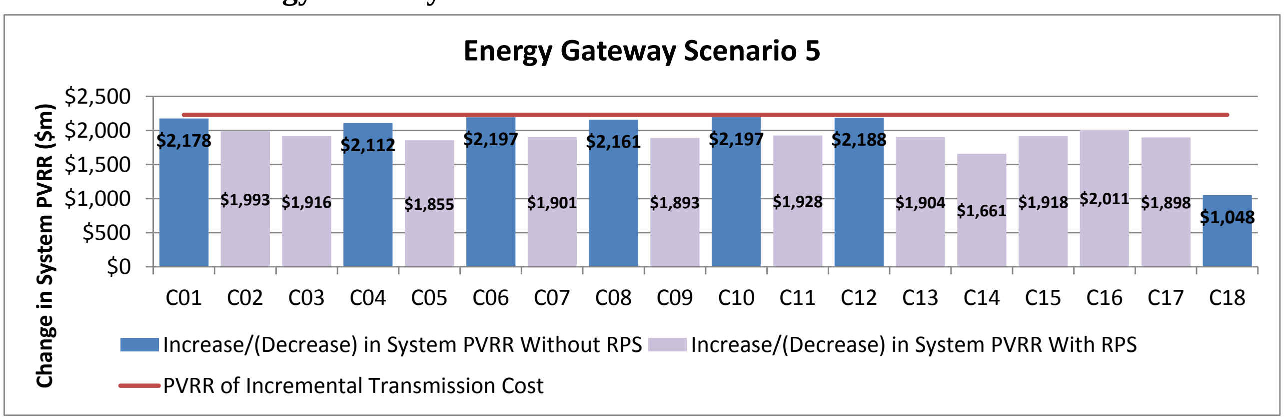


Figure 8.10 – PVRR Difference in System Costs between Like Portfolios in Energy Gateway Scenario 5 and Energy Gateway Scenario 1



Summary of Portfolios among Core Case Themes

- Reference Cases: Cases in the Reference Case Theme are characterized by base/medium assumptions with varying types of RPS assumptions.
  - Differences among portfolios in this theme are driven by RPS policy assumptions.

- When no RPS assumptions are made, there are very small quantities of large utility-scale renewable resources selected. In these cases, wind resource additions range between zero and 78 MW through 2032.
- When state RPS assumptions are applied, renewable resources are added at levels required to achieve compliance. In Energy Gateway Scenario 1, wind additions total 600 MW and "large scale" solar photovoltaic (PV) additions total 28 MW by 2032. Among Energy Gateway Scenarios 2 through five, wind resource additions range between 759 MW and 829 MW by 2032.
- With both state and federal RPS assumptions, renewable resources are added at levels to achieve compliance with targets. In Energy Gateway Scenario 1, incremental wind resources total 803 MW and a 227 MW large scale solar PV resource is added in 2026. Among Energy Gateway Scenarios 2 through 5, wind resource additions range between 858 MW and 928 MW by 2032.

- Environmental Policy Cases: Cases in the Environmental Policy Theme are characterized by varying combinations of commodity market prices, CO_2 prices, RPS requirements, and Regional Haze requirements.
  - The impact of RPS assumptions on renewable resource additions is similar to those observed among cases in the Reference Theme, whereby no to limited amounts of incremental renewable resources are added to the resource portfolio when RPS compliance obligations are removed.
  - Alternative Regional Haze assumptions did not drive changes in coal unit early retirement and natural gas conversions.
  - Incremental environmental investments in coal units are made in favor of early retirement and gas conversion alternatives for nearly all units and in nearly all cases where where medium natural gas prices are combined with medium CO_2 price and medium coal cost assumptions, and in cases where high natural gas prices are combined with zero CO_2 prices and low coal costs.
  - Under cases defined by low natural gas prices combined with high CO_2 prices and high coal costs (cases C04, C05, C08, and C09), nearly all of PacifiCorp's existing coal-fired resources are retired or converted to natural gas prior to 2032.
  - When U.S. hard cap CO_2 prices are assumed, the resulting portfolios reflect coal retirements and gas conversions similar to the levels seen in cases C04, C05, C08, and C09.

- Targeted Resource Cases: Cases in the Targeted Resource Theme are characterized by alternative assumptions for specific resource types to understand how they influence resource portfolio costs and risk.
  - Case C15 assumes energy efficiency resources (Class 2 DSM) can be acquired at an accelerated rate and disallows selection of new CCCT generation assets. High level adjustments were applied to the 2012 DSM Potential study measures and ramp rates to allow selection of up to two percent of 2011 actual sales in each state. After discretionary resources are exhausted, annual Class 2 DSM opportunities decrease, with remaining resources from equipment upgrades and new construction. As compared to core cases with base Class 2 DSM resource availability, System Optimizer model selected additional Class 2 DSM resources earlier in the planning horizon, and as intended, this portfolio does not include any new CCCT resources through the 20 year planning period.

- Case C16 assumes that state and federal RPS obligations must first be met with available geothermal power purchase agreement (PPA) resources among five sites located in PacifiCorp's service territory. In this case, 145 MW of geothermal PPA resource is added and supplemented with additional wind resources as required to meet RPS requirements. With the addition of the geothermal PPA resources, the 227 MW large utility-scale solar PV resources added in 2026 in reference case C03 under Energy Gateway Scenario 1 is displaced.
- Case C17 assumes forward power prices under a high natural gas price scenario increase by 50 percent during on-peak hours and by 30 percent in off-peak hours. In this case, FOT resources are reduced, but not eliminated, and a CCCT natural gas resource is added to the portfolio in 2017.
- Case C18 targets a "Clean Energy Bookend" portfolio and is defined with high natural gas prices, high power prices, and U.S hard cap CO_2 price assumptions along with extension of federal tax incentives for renewable resources through 2019. The resulting portfolio includes incremental renewable resources beyond 2019, early coal unit retirements and gas conversions beginning 2023, a nuclear resource in 2025, and an integrated gasification combined cycle unit (IGCC) with carbon capture and sequestration (CCS) in 2032.

- Transmission Case: The Transmission Theme includes one core case assuming that transmission can be purchased from a new line built by a third party as an alternative to the Company's Energy Gateway Segment D project. Resource selections in this case do not vary significantly from those observed in reference case C03.

Carbon Dioxide Emissions

Figures 8.11 through 8.13 show annual CO_2 emissions from resource portfolios under Energy Gateway Scenario 2 grouped by core case theme.[71] All cases show emission reductions over the 20 year planning horizon with the assumed end-of-life retirement of existing coal units. Longer-term addition of renewable resources among those cases with RPS assumptions and longer-term addition of natural gas resources, required to meet load growth and assumed end-of-life coal unit retirements, also contribute to lower emission levels. Portfolios showing the most dramatic CO_2 emission reductions include those cases in the Environmental Policy and Targeted Resource Themes producing portfolios with extensive early coal unit retirements and gas conversions (cases C04, C05, C08, C09, C15, and C18).

[71] Similar emission trends are observed among other Energy Gateway Scenarios.

Figure 8.11 – Annual CO_2 Emissions: Reference Cases

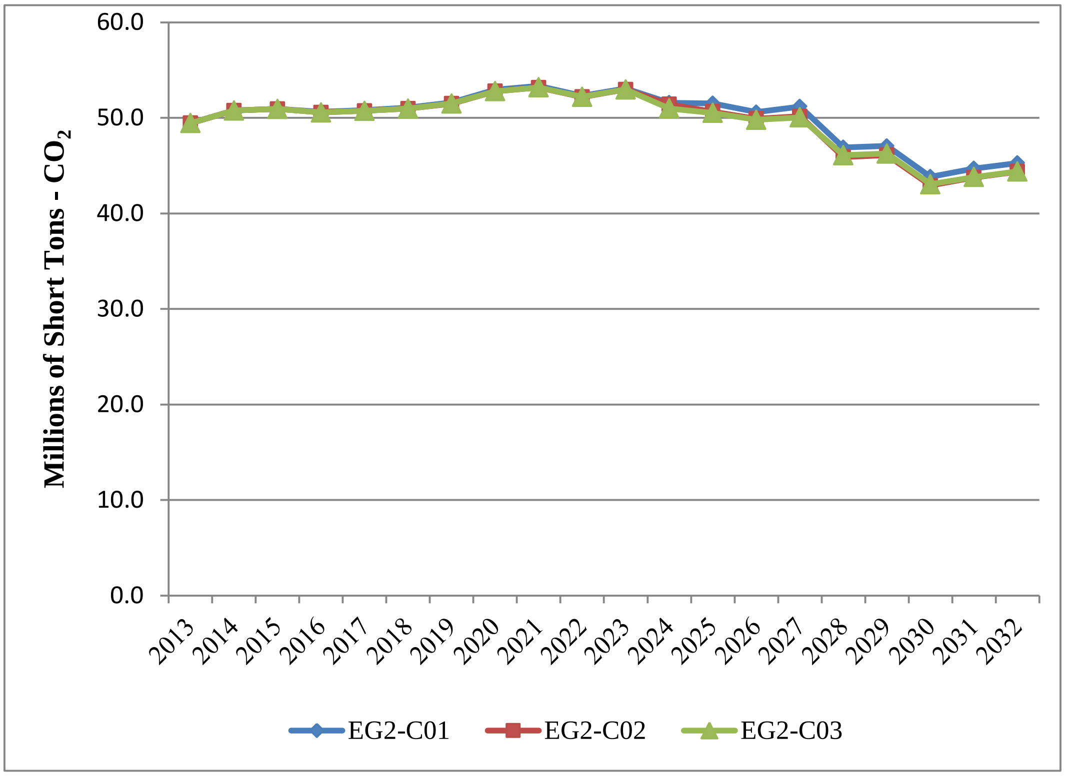


Figure 8.12 – Annual CO_2 Emissions: Environmental Policy

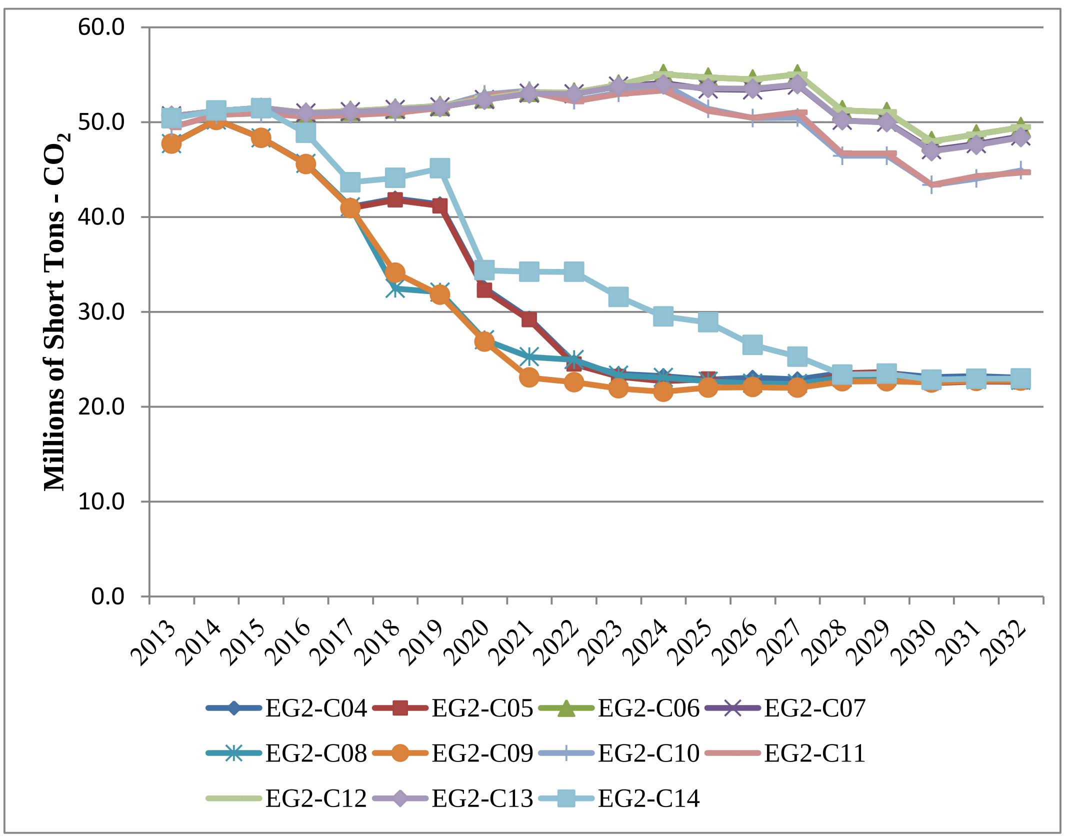
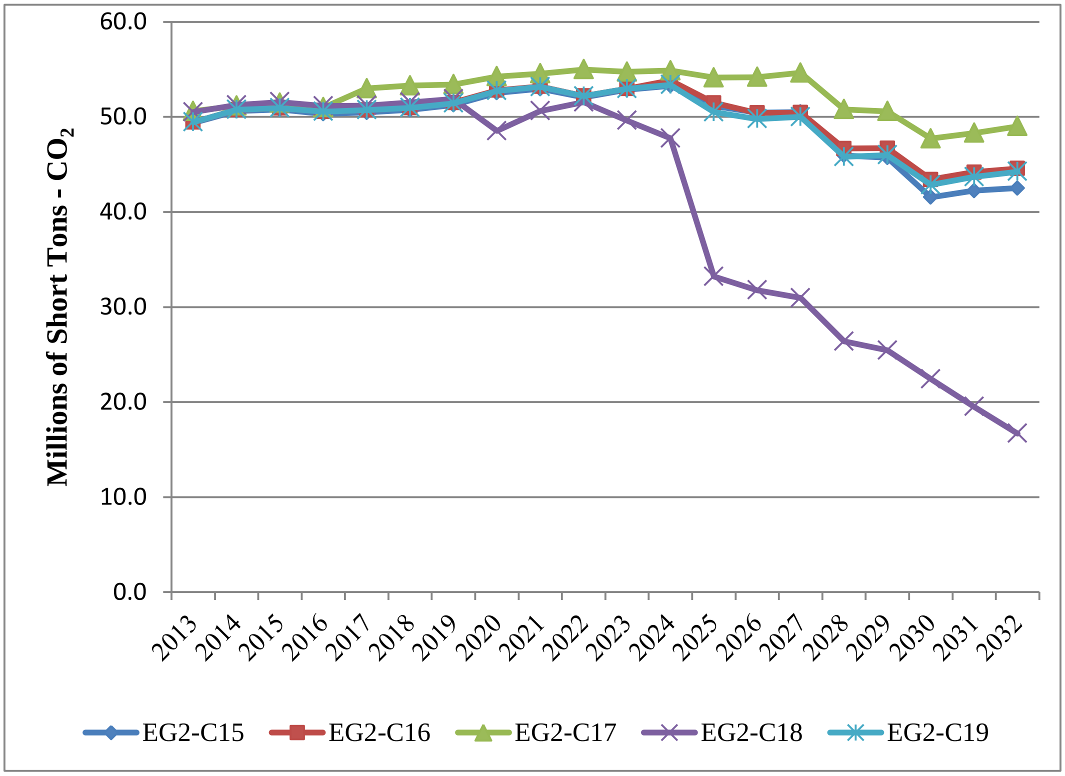


Figure 8.13 – Annual CO_2 Emissions: Targeted Resources



Pre-Screening Results

As described in Chapter 7, the Company tested in the Planning and Risk model (PaR) 36 core case portfolios from Energy Gateway Scenarios 1 and 2 with the application of stochastic Monte Carlo simulation of market prices, loads, thermal outages and hydro generation, across three CO_2 price levels (zero, medium, and high). Pre-screening of portfolios was performed by producing scatter plots of stochastic mean and upper tail mean *less* stochastic mean PVRR results using data from the PaR simulations among each CO_2 price scenario.[72] The resulting scatter plots, shown in Figures 8.14 through 8.19, were used to identify portfolios that are extreme cost and or risk outliers relative to other portfolios. The red dashed line depicted on each of the following figures demarcates the threshold used to identify outlier portfolios. Portfolios to the left and below the dashed red line are lower cost and lower risk and were designated as superior relative to those portfolios to the right and above the red dashed line.

[72] Netting the stochastic mean PVRR from the upper tail mean PVRR is done to isolate fixed costs common to both metrics.

Figure 8.14 – Remove Outliers, Energy Gateway Scenario 1 with Zero CO2 Prices

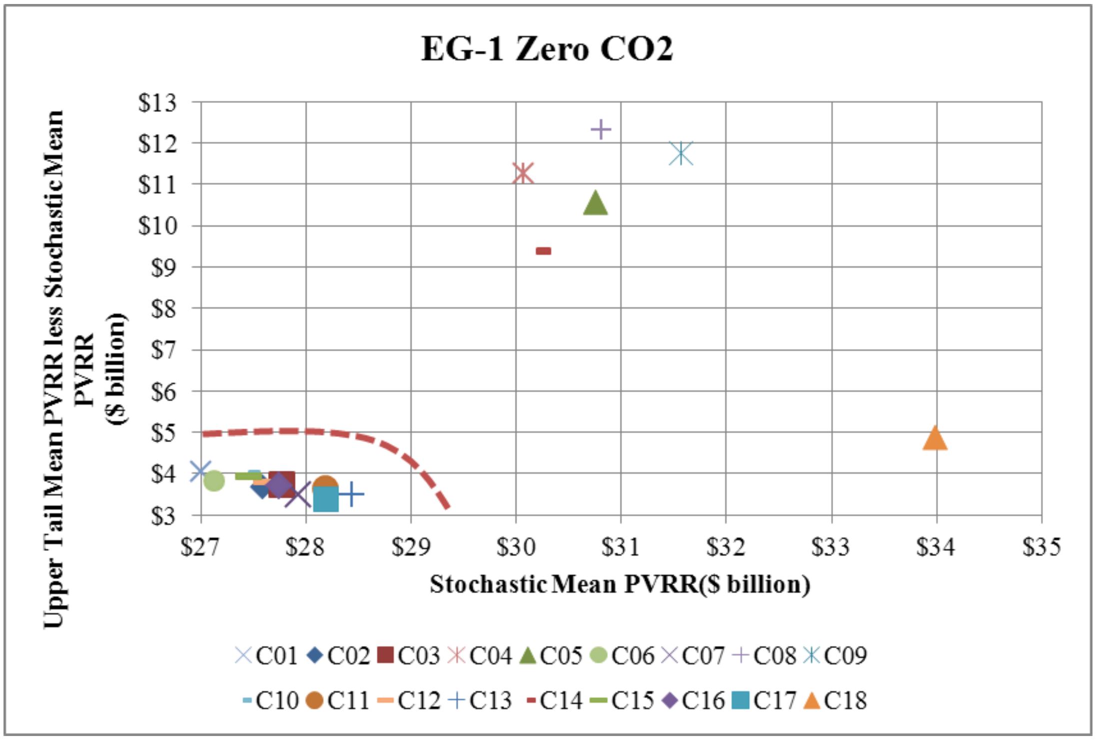


Figure 8.15 – Remove Outliers, Energy Gateway Scenario 1 with Medium CO_2 Prices

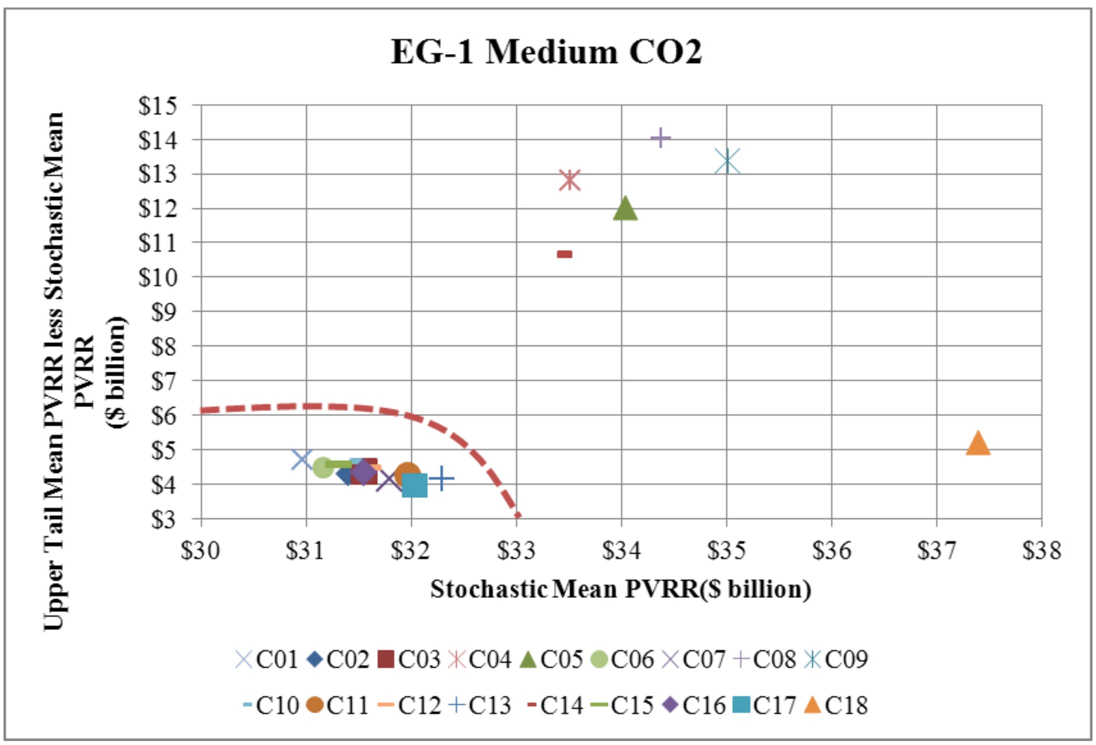


Figure 8.16 – Remove Outliers, Energy Gateway Scenario 1 with High CO_2 Prices

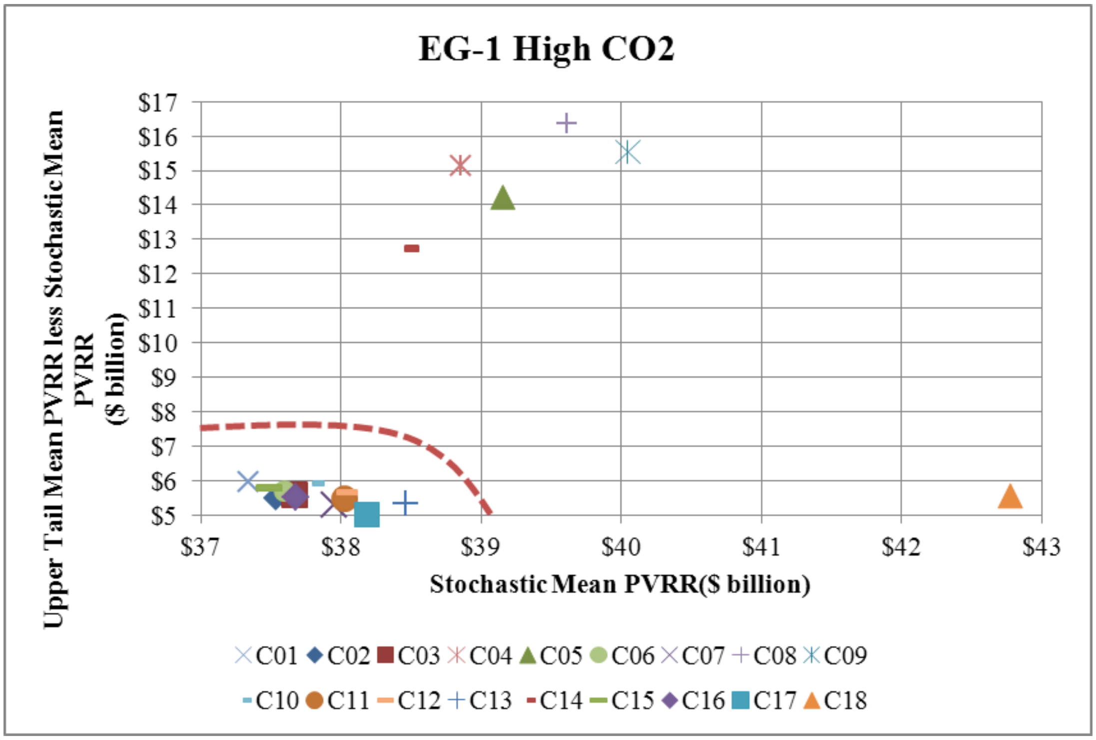


Figure 8.17 – Remove Outliers, Energy Gateway Scenario 2 with Zero CO2 Prices

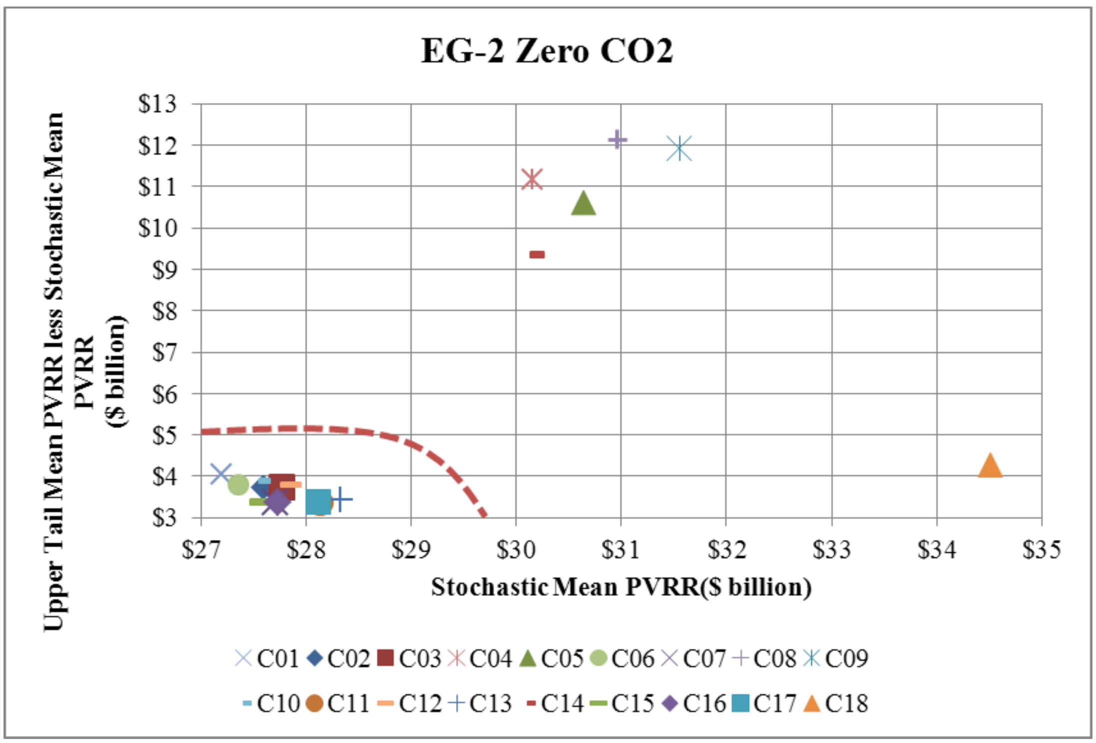


Figure 8.18 – Remove Outliers, Energy Gateway Scenario 2 with Medium CO_2 Prices

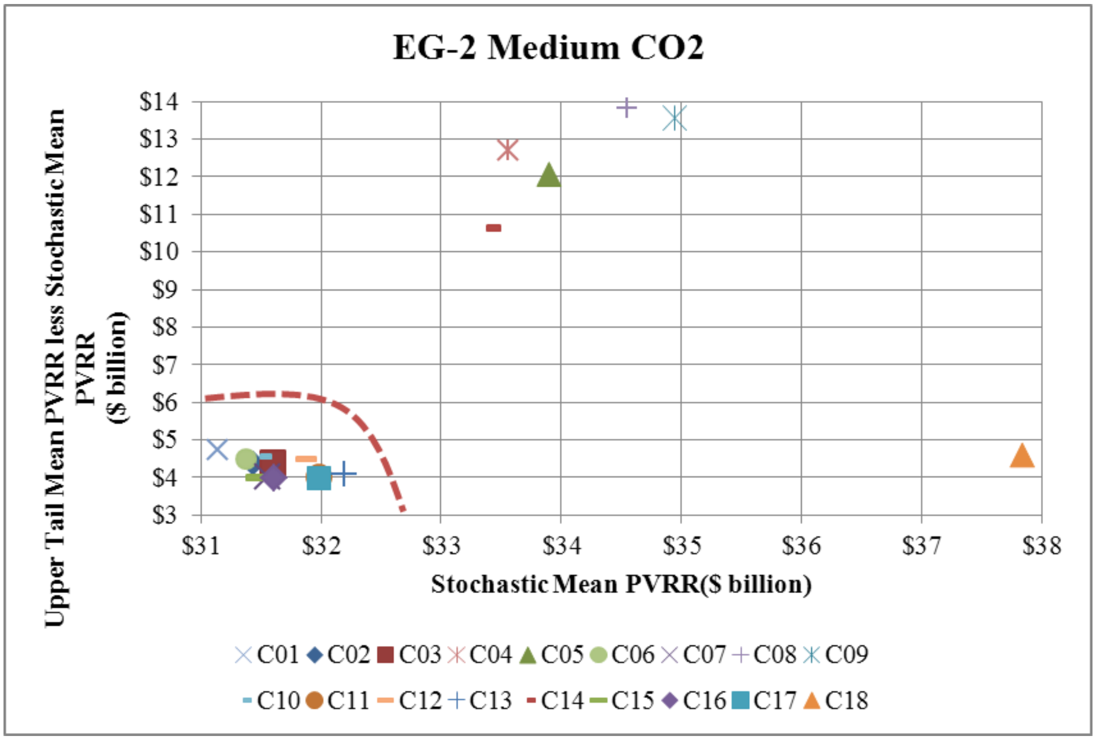
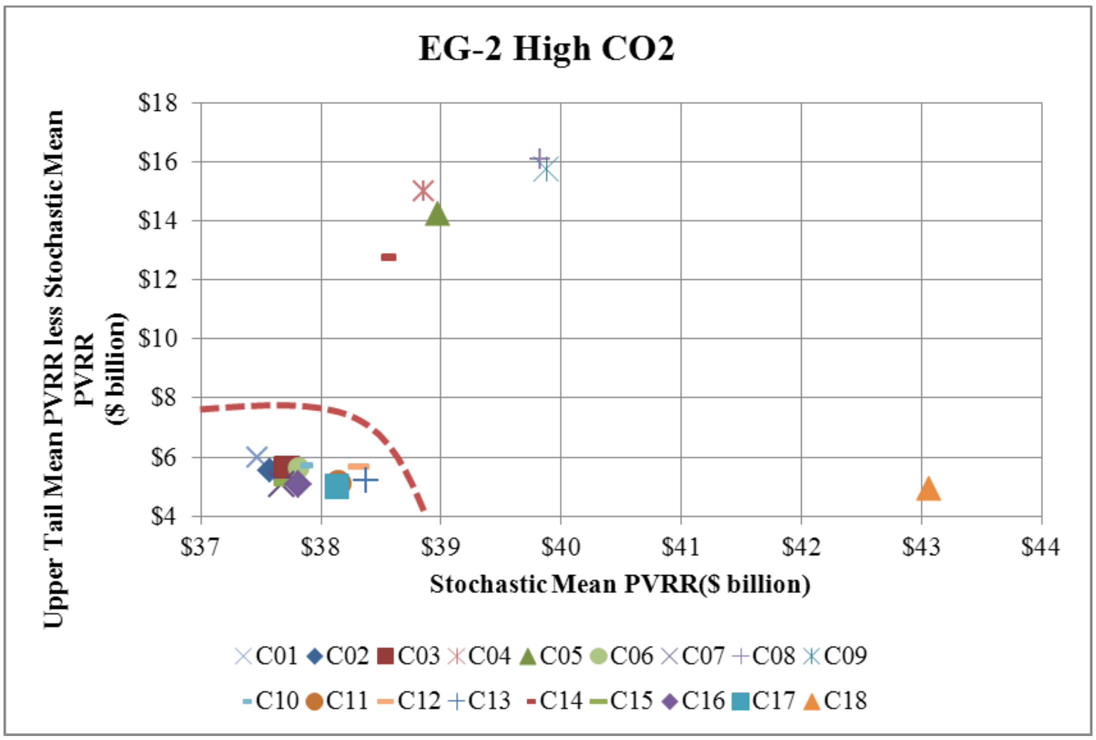


Figure 8.19 – Remove Outliers, Energy Gateway Scenario 2 with High CO_2 Prices



A consistent set of portfolios among each CO_2 price scenario and for each Energy Gateway scenario are outliers in relation to other portfolios included on the above plots. These portfolios, each characterized by extensive early coal unit retirements and gas conversions (cases C04, C05, C08, C09, C14, and C18), were removed from consideration as candidates for the preferred portfolio. As an additional pre-screening step, the case C19 portfolio was removed from consideration because the case is predicated on completion of a third party transmission project (the Zephyr DC line), which is not currently far enough into the development process for it to be considered for the preferred portfolio.[73] Similarly, portfolios that cannot meet compliance with state and assumed federal RPS requirements were also removed from consideration. As a result, the portfolios identified in the pre-screening analysis as potential preferred portfolio candidates include portfolios from cases C03, C07, C11, C13, C15, C16 and C17 under Energy Gateway Scenarios 1 and 2 (14 portfolios).

Initial Screening Results

With the removal of pre-screened portfolios, scatter plots of the stochastic mean PVRR and the stochastic mean PVRR less the upper tail mean PVRR can be viewed with finer resolution. Figures 8.20 to 8.22 show these scatter plots for the 14 portfolios identified in the pre-screening analysis under zero, medium and high CO_2 price levels. The red line demarcates the group of portfolios designated as superior with respect to the combination of the cost and risk metrics. The red demarcation line is established by calculating a cost/risk variance threshold using two percent of the stochastic mean PVRR of the least cost portfolio under each CO_2 price scenario and applying this threshold to the least cost and least risk portfolios on each scatter plot. For example, under medium CO_2 price scenario, the least cost portfolio has a stochastic mean PVRR of $31.3 billion. Two percent of this figure is $630 million, which is the threshold used for the medium CO_2 price scenario. Any portfolio that is within $630 million of the lowest cost portfolio *and* within $630 million of the least risk portfolio in the medium CO_2 price scenario is to the left and blow the red dashed line. The cost /risk threshold used in the zero and high CO_2 scenarios is $550 million and $750 million, respectively.

[73] The Zephyr DC line would provide no reliability benefits to PacifiCorp's existing transmission system and may require additional infrastructure additions to meet reliability for the existing system. The line does not provide interconnection for of new resources except at the termination points established if the project were constructed and does not allow for multiple interconnection points with the existing PacifiCorp transmission system. The proposed line with PacifiCorp transmission is more expensive than Energy Gateway Segment D.

Figure 8.20 – Stochastic mean PVRR versus Upper-tail Risk with Zero CO_2 Prices

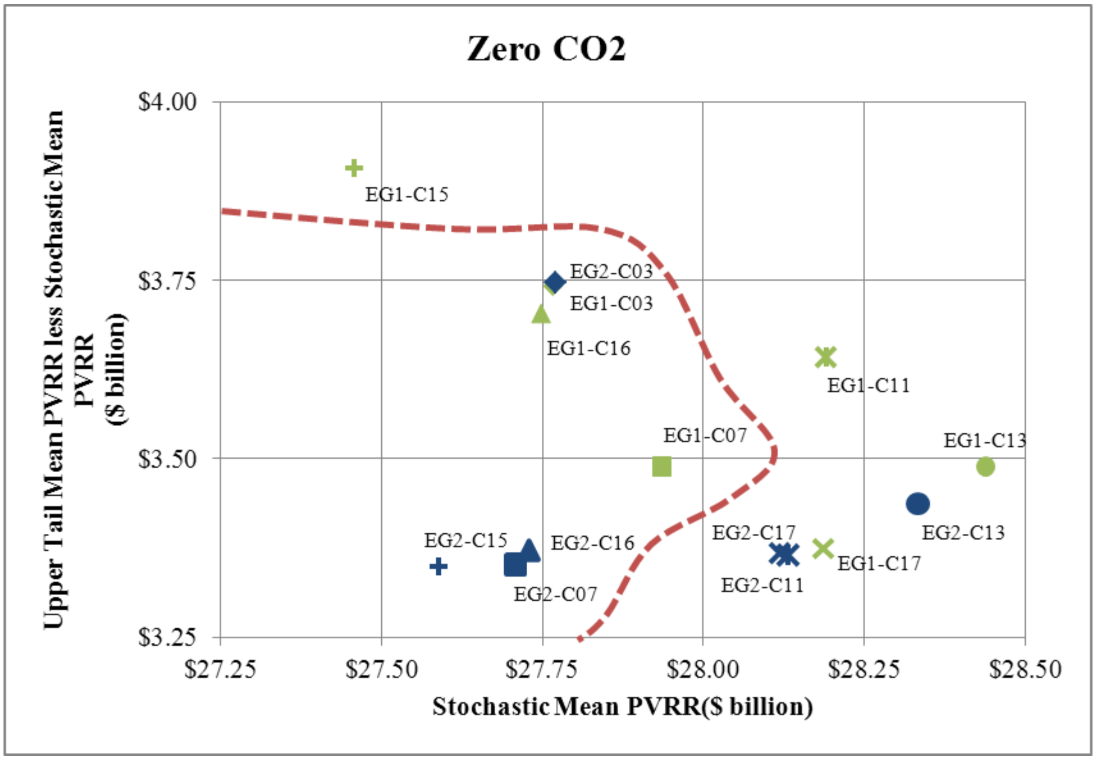


Figure 8.21 – Stochastic mean PVRR versus Upper-tail Risk with Medium CO_2 Prices

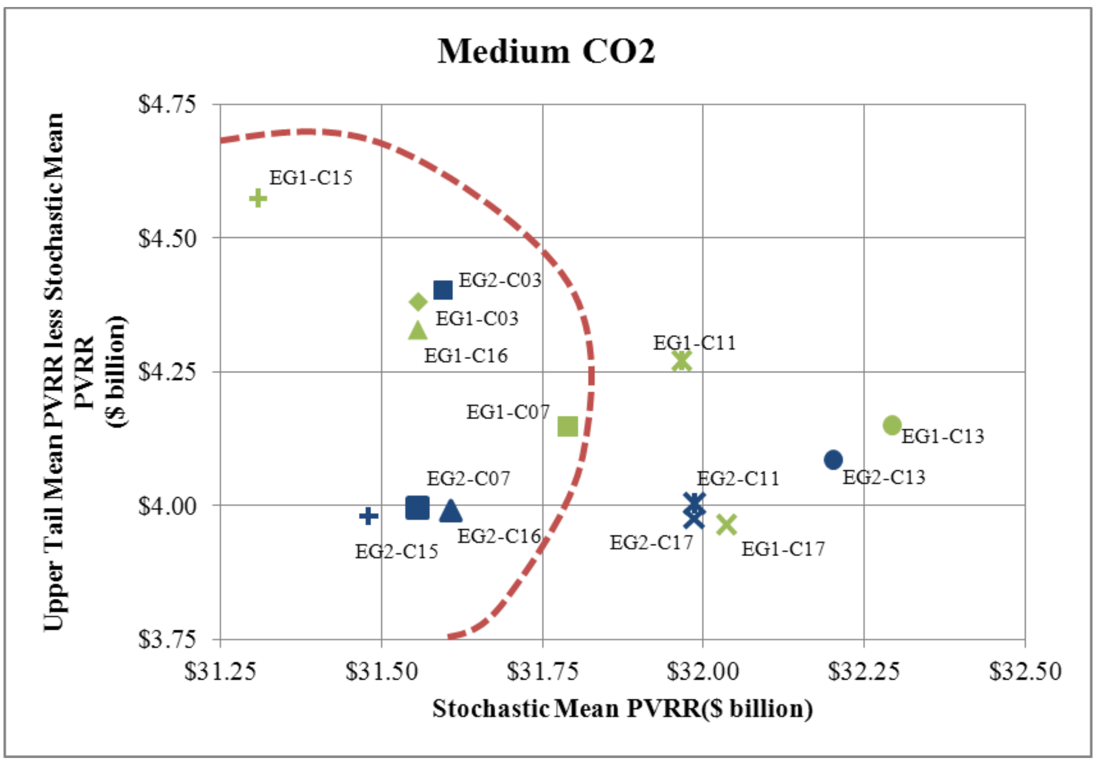
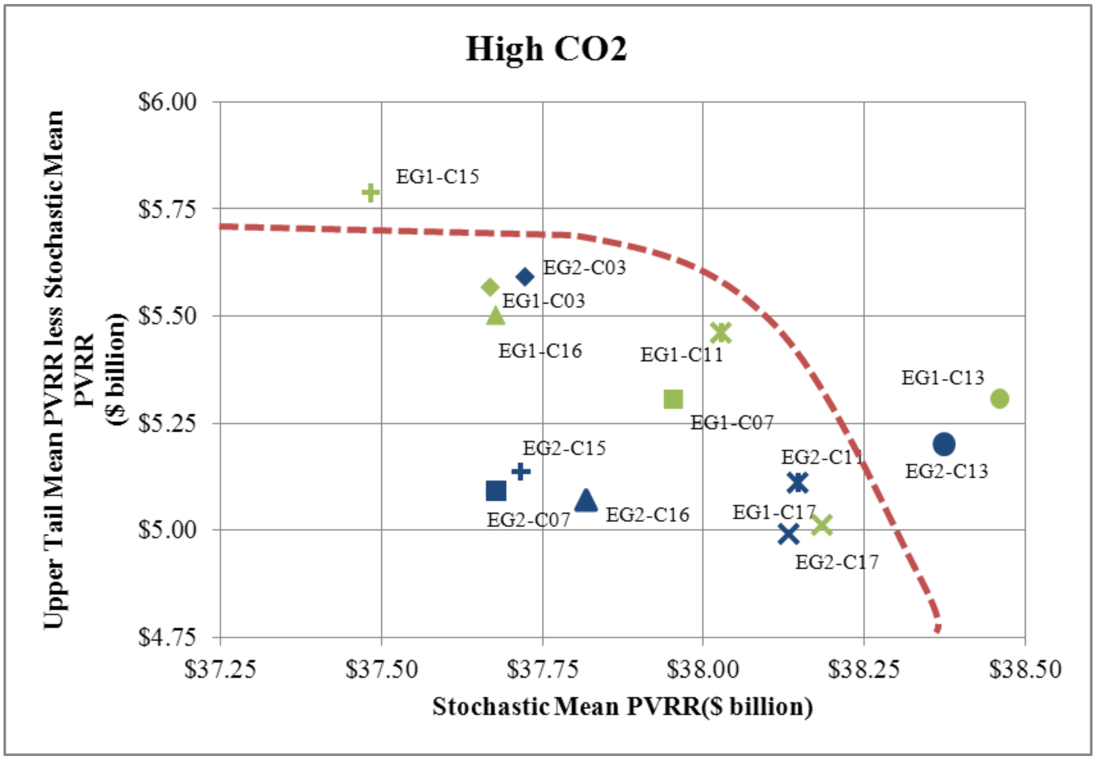


Figure 8.22 – Stochastic mean PVRR versus Upper-tail Risk with High CO_2 Prices



Portfolios that fall within the threshold identified by the red dashed line in the figures above under *any* CO_2 price scenario are considered as candidates for the preferred portfolio and passed along for final screening. Based upon the initial screening scatter plot analysis, which shows there is very little separation between portfolios, the top performing portfolios using least cost/least risk metrics include portfolios from cases C03, C07, C11, C15, C16 and C17 under Energy Gateway Scenarios 1 and 2 (12 portfolios).

Final Screening Results

Risk-adjusted PVRR

The risk adjusted PVRR is one of the primary metrics used to rank and inform selection of the preferred portfolio. As described in Chapter 7, this metric combines cost and risk attributes from the PaR model by expressing a low probability portfolio cost outcome as a risk premium to the expected PVRR.[74] Table 8.1 reports the risk-adjusted PVRR values and relative ranking among the 12 portfolios identified in the initial screening analysis by CO_2 price scenario. Portfolios developed under core case C15 under Energy Gateway Scenarios 1 and 2 (EG1-C15 and EG2-C15, as depicted in the table below), which eliminates the possibility of new CCCT resources and assumes accelerated acquisition of Class 2 DSM resources, rank high on a risk adjusted PVRR basis. The portfolio developed under core case C07 under Energy Gateway Scenario 2 also ranks high, ranking just below the C15 cases in the zero and medium CO_2 scenarios and ranking second, above the portfolio developed under case C15 from Energy Gateway Scenario 2, when high CO_2 prices are assumed.

[74] This risk adjusted PVRR is calculated as the stochastic mean PVRR plus five percent of the 95th percentile of the variable production cost PVRR, excluding fixed costs.

Table 8.1 – Portfolio Comparison, Risk-adjusted PVRR

	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
Case	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank
EG1-C03	$28,719	$306	7	$32,717	$245	4	$39,175	$179	3	$33,537	$244	5
EG1-C07	$28,894	$481	8	$32,956	$485	8	$39,476	$480	8	$33,775	$482	8
EG1-C11	$29,140	$727	11	$33,123	$651	11	$39,529	$534	9	$33,931	$637	11
EG1-C15	$28,413	$0	1	$32,471	$0	1	$38,996	$0	1	$33,293	$0	1
EG1-C16	$28,703	$290	6	$32,718	$247	5	$39,186	$191	5	$33,536	$243	4
EG1-C17	$29,146	$733	12	$33,203	$732	12	$39,694	$699	12	$34,014	$721	12
EG2-C03	$28,695	$282	5	$32,729	$257	6	$39,203	$208	6	$33,542	$249	6
EG2-C07	$28,621	$208	3	$32,679	$208	3	$39,149	$153	2	$33,483	$190	3
EG2-C11	$29,045	$632	10	$33,108	$636	9	$39,618	$622	11	$33,924	$630	9
EG2-C15	$28,494	$81	2	$32,595	$123	2	$39,186	$191	4	$33,425	$131	2
EG2-C16	$28,646	$233	4	$32,735	$263	7	$39,295	$299	7	$33,558	$265	7
EG2-C17	$29,044	$631	9	$33,120	$648	10	$39,607	$612	10	$33,924	$630	10

Cumulative Carbon Dioxide Emissions

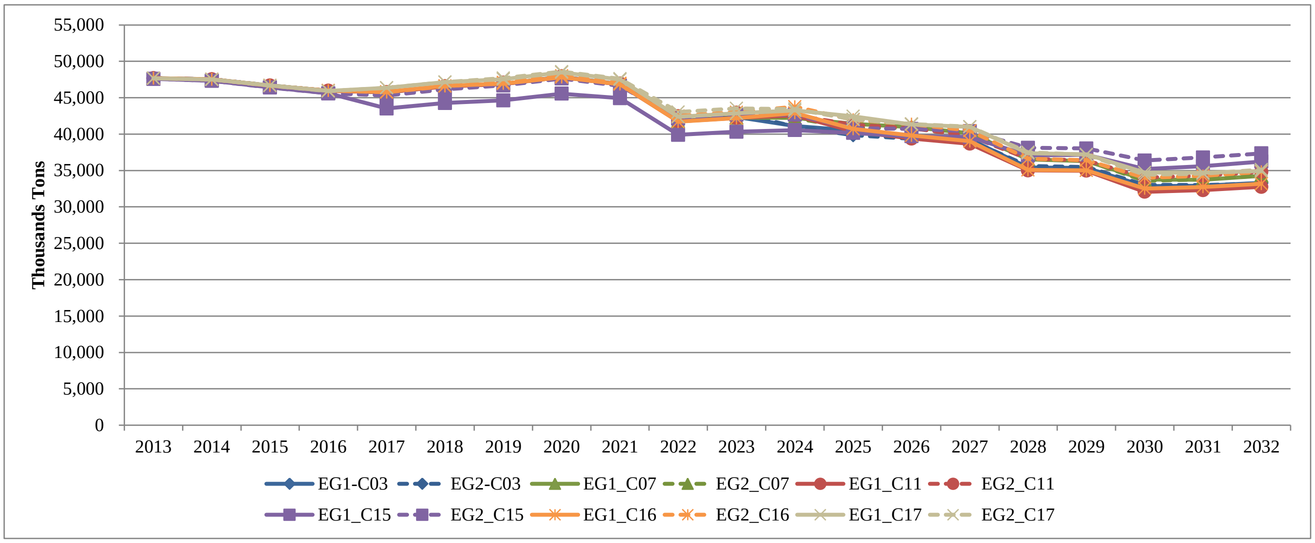
Table 8.2 reports the average cumulative 20-year CO_2 emissions (average of the 100 Monte Carlo iterations) for each of the 12 portfolios identified in the initial screening analysis. The EG1-C15 portfolio has slightly lower CO_2 emissions beginning 2017, but emissions are higher in longer-term given the absence of base load combined cycle combustion turbine resources. The difference between the average annual emissions in the highest ranking portfolio and the lowest ranking portfolio in the medium CO_2 scenario is 1.3 million tons, or 3% of annual system CO_2 emissions among all portfolios.

Table 8.2 –Portfolio Comparison, Cumulative CO_2 Emissions for 2013-2032

	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
Case	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank	Total CO2 Emissions, 2013-2032 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
EG1-C03	871,984	9,220	3	836,154	4,773	3	803,958	2,917	3	837,365	4,990	3
EG1-C07	884,725	21,962	6	845,061	13,680	6	811,879	10,838	6	847,222	14,847	6
EG1-C11	871,047	8,283	2	833,753	2,372	2	801,042	0	1	835,280	2,905	2
EG1-C15	862,764	0	1	831,381	0	1	802,982	1,940	2	832,375	0	1
EG1-C16	873,506	10,743	4	836,778	5,397	4	804,491	3,449	5	838,258	5,883	4
EG1-C17	896,136	33,372	11	857,056	25,675	11	824,668	23,626	10	859,286	26,911	11
EG2-C03	873,964	11,200	5	837,300	5,919	5	804,480	3,439	4	838,581	6,206	5
EG2-C07	884,841	22,077	7	845,998	14,616	7	813,184	12,143	7	848,008	15,632	7
EG2-C11	886,356	23,593	8	848,108	16,727	8	815,771	14,730	8	850,079	17,703	8
EG2-C15	889,384	26,621	10	855,418	24,037	10	824,930	23,889	11	856,578	24,202	10
EG2-C16	888,635	25,871	9	851,427	20,046	9	820,124	19,083	9	853,395	21,020	9
EG2-C17	897,356	34,592	12	858,353	26,972	12	825,533	24,492	12	860,414	28,039	12

While there are differences in cumulative CO_2 emissions among each of the portfolios that are used to rank the portfolios under each of the CO_2 price scenarios, as shown in Figure 8.23, the expected emission levels among the 12 portfolios identified in the initial screening analysis are very similar over the 20 year planning period.

Figure 8.23 – Stochastic Mean Annual CO_2 Emissions with Medium CO_2 Prices



Supply Reliability

Table 8.3 and Table 8.4 report two measures of stochastic supply reliability, average annual energy not served (ENS) and upper-tail mean ENS, for each of the 12 portfolios identified in the initial screening analysis. The portfolios developed under case EG1-C15 and EG2-C11 perform the best on these two measures, and differences among portfolios are not material between CO_2 price scenarios. The high ranking of the portfolio developed under case EG1-C15 is largely influenced by west side Class 1 DSM resources that were added over the period from 2020 to 2025.

Table 8.3 – Portfolio Comparison, Stochastic Mean Energy Not Served

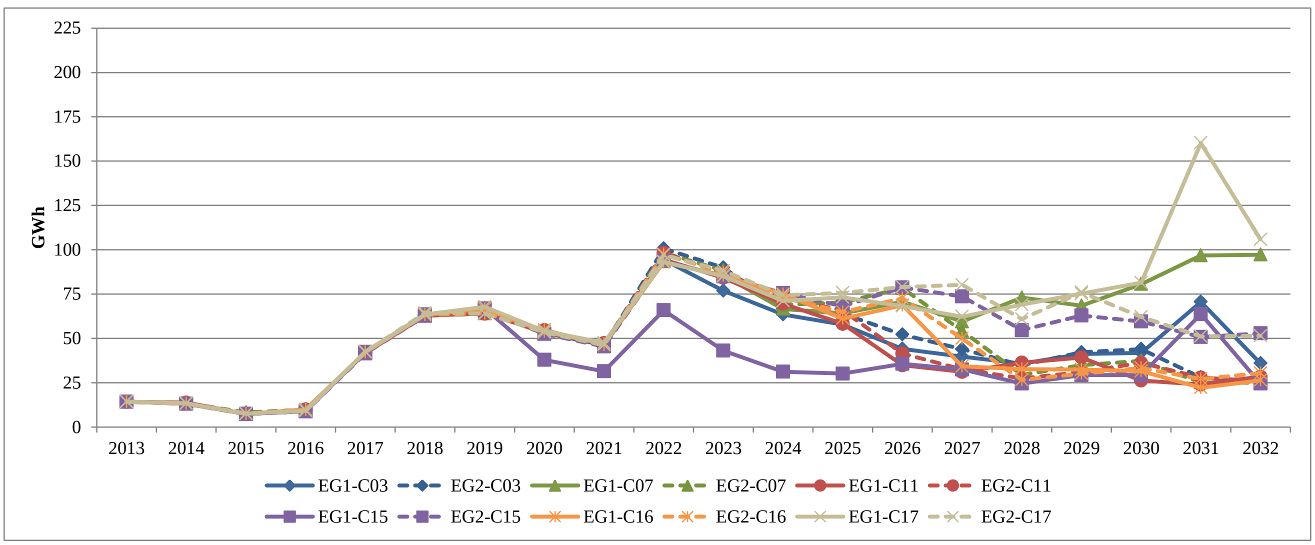
	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
Case	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank
EG1-C03	44.9	10.5	8	46.0	11.1	7	47.1	11.3	5	46.0	11.0	7
EG1-C07	56.8	22.4	11	58.8	23.8	11	61.6	25.7	11	59.0	24.0	11
EG1-C11	40.9	6.5	3	42.3	7.3	2	44.2	8.3	2	42.5	7.4	2
EG1-C15	34.4	0.0	1	35.0	0.0	1	35.8	0.0	1	35.1	0.0	1
EG1-C16	42.4	8.0	4	44.3	9.3	4	46.5	10.7	3	44.4	9.4	4
EG1-C17	61.5	27.0	12	63.6	28.6	12	66.0	30.2	12	63.7	28.6	12
EG2-C03	42.7	8.3	6	45.6	10.7	6	49.0	13.2	7	45.8	10.7	6
EG2-C07	43.2	8.8	7	46.6	11.6	8	50.7	14.9	8	46.8	11.8	8
EG2-C11	40.6	6.2	2	43.3	8.3	3	46.8	11.0	4	43.6	8.5	3
EG2-C15	51.5	17.0	9	53.6	18.7	9	55.6	19.7	9	53.5	18.5	9
EG2-C16	42.7	8.3	5	45.6	10.6	5	48.9	13.1	6	45.8	10.7	5
EG2-C17	51.7	17.3	10	55.8	20.9	10	60.8	25.0	10	56.1	21.1	10

Table 8.4 – Portfolio Comparison, Energy Not Served - Upper Tail

	Zero CO2			Medium CO2			High CO2			CO2 Scenario Average		
Case	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2013-2032 (GWh)	Change from Lowest ENS Portfolio	Rank
EG1-C03	69.2	10.7	4	70.9	14.8	2	75.7	15.2	2	71.9	13.6	2
EG1-C07	97.9	39.4	11	104.2	48.2	11	115.6	55.1	10	105.9	47.5	11
EG1-C11	71.2	12.7	5	73.0	17.0	3	86.8	26.3	3	77.0	18.7	3
EG1-C15	58.5	0.0	1	56.1	0.0	1	60.5	0.0	1	58.4	0.0	1
EG1-C16	73.3	14.8	7	77.3	21.2	6	91.9	31.4	4	80.8	22.5	5
EG1-C17	106.0	47.5	12	105.1	49.0	12	113.8	53.3	9	108.3	49.9	12
EG2-C03	68.6	10.1	3	75.4	19.3	5	99.3	38.8	6	81.1	22.7	6
EG2-C07	77.1	18.6	8	89.3	33.3	9	118.4	57.9	11	94.9	36.6	9
EG2-C11	66.9	8.4	2	74.5	18.5	4	95.1	34.6	5	78.8	20.5	4
EG2-C15	82.3	23.8	9	86.3	30.2	8	102.4	41.9	8	90.3	32.0	8
EG2-C16	71.7	13.2	6	84.3	28.2	7	102.0	41.5	7	86.0	27.6	7
EG2-C17	82.6	24.1	10	99.2	43.1	10	133.4	72.9	12	105.1	46.7	10

Most of the differences in ENS ranking of stochastic mean are largely driven by changes in portfolios beyond the first ten years of the IRP planning horizon. Figure 8.24 shows the annual stochastic mean ENS among the 12 portfolios identified in the initial screening analysis under the medium CO_2 price scenario.

Figure 8.24 – Stochastic Mean Annual ENS with Medium CO_2 Prices



Preferred Portfolio Selection

Based upon the metrics reviewed in the final screening analysis, and given similarities among portfolios, particularly in the near-term, with regard to CO_2 emissions and ENS as reported by the PaR model, PacifiCorp has primarily relied upon the risk adjusted net PVRR results and the associated portfolio rankings to inform preliminary selection of a preferred portfolio.

Deliverability of Accelerated Class 2 DSM and Resource Constraints

Portfolios developed under case C15 for Energy Gateway Scenarios 1 and 2 have the highest risk adjusted net PVRR ranking among candidate portfolios across different CO_2 price scenarios.[75] Portfolios developed under case C15 assume that acquisition of Class 2 DSM resources can be accelerated and was developed absent the opportunity for cost effective selection of CCCT resources. High level adjustments were applied to base case measure costs and ramp rates to develop the input assumptions required to develop this portfolio using the System Optimizer model. While the risk adjusted net PVRR results for the two C15 portfolios rank high in relation to other candidate portfolios, the Company has *not* chosen the C15 portfolios as the preferred portfolio for the following reasons:

- The high level cost assumptions underlying selection of the accelerated Class 2 DSM resources are uncertain. The Company does not have strong evidence in support of the true acquisition costs.
- Ramp rate assumptions underlying selection of the accelerated Class 2 DSM resources are untested ramp rate modifications. The Company does not have strong evidence that the revised ramp rate assumptions are achievable given regulatory and market factors.
- The Company is reluctant to select a portfolio that was developed with the exclusion of an entire class of proven resource technology. It is not reasonable to consider a portfolio that on the outset precludes consideration of CCCT resources throughout the entire 20 year planning horizon.

Nonetheless, the potential benefits of acquiring Class 2 DSM early is highlighted in the C15 portfolio results, and specific action items have been included in the 2013 IRP Action Plan (Chapter 9) targeting accelerated acquisition of cost-effective Class 2 DSM resources.

Resource Diversity

Figure 8.25 summarizes the nameplate capacity of cumulative resource selection through 2022 among the six portfolios beyond the C15 cases that rank highest on a risk adjusted net PVRR basis. This figure illustrates the similarity among the top performing portfolios, identified using cost and risk metrics, through the first 10 years of the planning period – the timeframe most critical to influencing the 2013 IRP Action Plan. With reduced loads and market prices, each portfolio is dominated by Class 2 DSM resources and FOT resources.[76] None of the portfolios include a CCCT resource over this period. Among these portfolios, renewable resources are added in different quantities and at different times for the sole purpose of meeting west side state RPS requirements. The variability in quantity, type, and timing of new renewable resources is dependent on whether the Windstar-Populus transmission project is built under the Energy Gateway Scenario 2.

[75] The C07 portfolio under Energy Gateway Scenario 2 outranks the C15 portfolio under Energy Gateway Scenario 2 when high CO_2 prices are assumed.

[76] Among the top ranking portfolios, no Class 1 DSM resources are added in the first 10 years of the planning period.

Figure 8.25 – Resource Types among Top Performing Portfolios

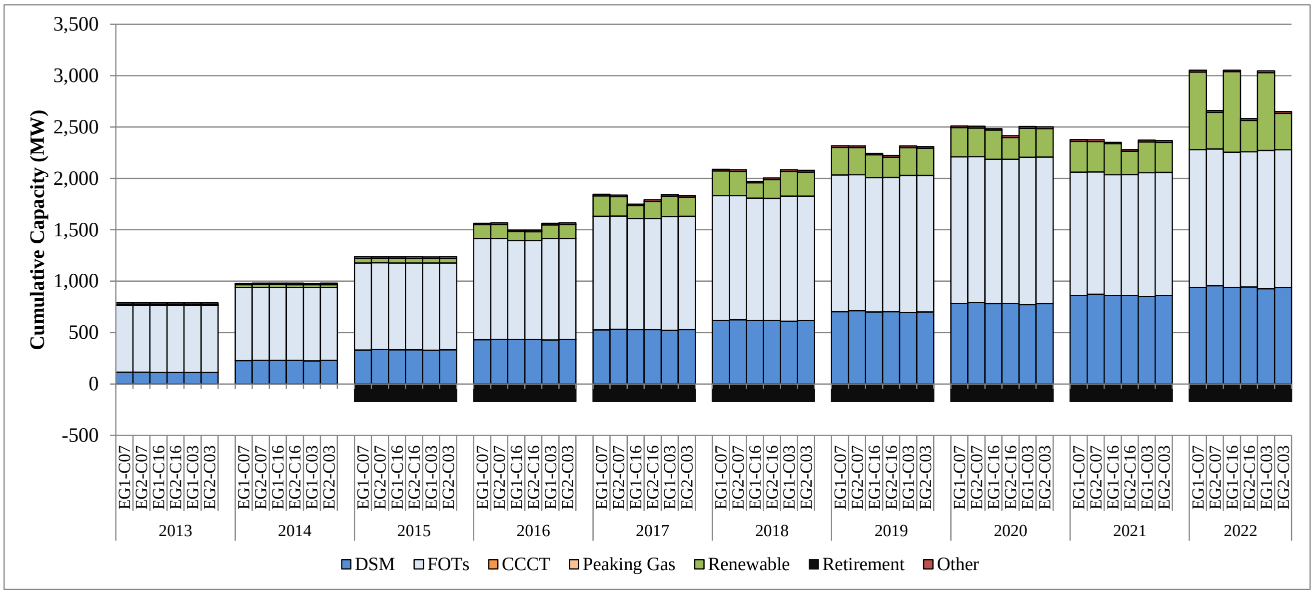


Table 8.5 reports the generation share in each portfolio among new resources by resource category for 2022 and 2032 for the six portfolios beyond the C15 cases that rank highest on a risk adjusted net PVRR basis. The resource categories reported include: thermal (including Lake Side 2), FOTs, renewable, and DSM programs.

Table 8.5 – Percentage Share of Generation of New Resources by Category

2022					
	Thermal	**FOTs**	**Renewable**	**DSM**	**Combined Renewables/ DSM**
EG1-C03	24%	21%	15%	39%	54%
EG1-C07	24%	21%	15%	39%	54%
EG1-C16	24%	20%	16%	38%	55%
EG2-C03	27%	23%	6%	42%	49%
EG2-C07	27%	23%	6%	43%	49%
EG2-C16	27%	23%	7%	43%	49%
2032					
	Thermal	**FOTs**	**Renewable**	**DSM**	**Combined Renewables/ DSM**
EG1-C03	26%	13%	15%	46%	60%
EG1-C07	38%	11%	14%	36%	50%
EG1-C16	26%	13%	15%	46%	61%
EG2-C03	27%	11%	16%	45%	61%
EG2-C07	35%	10%	14%	41%	55%
EG2-C16	28%	13%	17%	42%	59%

Preliminary Selection

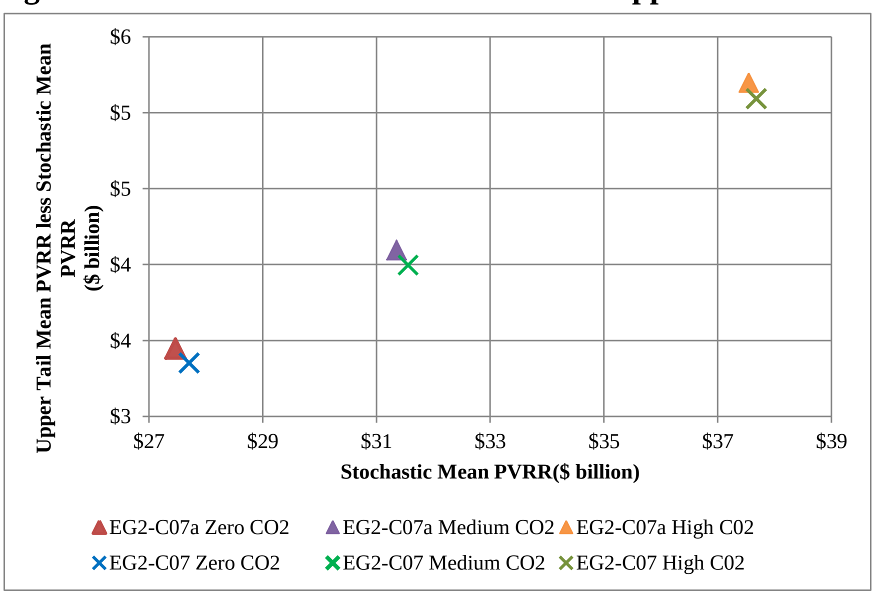
With consideration of the concerns around deliverability of Class 2 DSM resources in portfolios developed under case C15, portfolio C07 under Energy Gateway Scenario 2 ranks highest among the remaining portfolios on a risk-adjusted PVRR basis, and was selected as the preliminary preferred portfolio for the 2013 IRP. Selection of the portfolio developed under case C07 under Energy Gateway Scenario 2 is further supported by preliminary analysis using the SBT, showing net benefits with the addition of the Windstar-Populus project. These benefits would improve in the event the policy and market drivers affecting the addition of cost effective new renewables improve. The current SBT analysis of the Windstar-Populus project would further improve with prospective future additions of other Energy Gateway segments, which would increase the incremental capacity on the new line without any incremental cost.

Final Selection

Incremental wind resources included in the preliminary preferred portfolio prior to 2024 are included solely to meet the RPS compliance requirement in the state of Washington. However, there are potentially lower cost alternatives to meeting the Washington RPS requirement through the use of unbundled renewable energy credits. For this IRP, PacifiCorp performed an analysis that evaluated the use of unbundled renewable energy credits in meeting Washington RPS compliance requirements.

This alternative Washington RPS compliance strategy was performed by first developing an alternative to the EG2-C07 portfolio (EG2-C07a) using the System Optimizer model that excludes 208 MW of wind resources added to the system prior to 2024 that are used entirely for Washington RPS compliance.[77] In developing this portfolio, the System Optimizer model replaced the Washington situs assigned wind generation with alternative resources. The EG2-C07a portfolio was then analyzed in the PaR model under the same three CO_2 price assumptions used in the portfolio screening process described above. Figure 8.26 shows a scatter plot comparing the EG2-C07a portfolio to the EG2-C07 portfolio among the three different CO_2 price assumptions. As shown in the figure, under each CO_2 price scenario, EG2-C07a portfolio costs are lower and the upper tail risk metric is slightly higher.

Figure 8.26 – Stochastic Mean PVRR versus Upper-tail Risk with Zero CO_2 Prices



77 The 208 MW of wind that was removed spans the period 2016 through 2023.

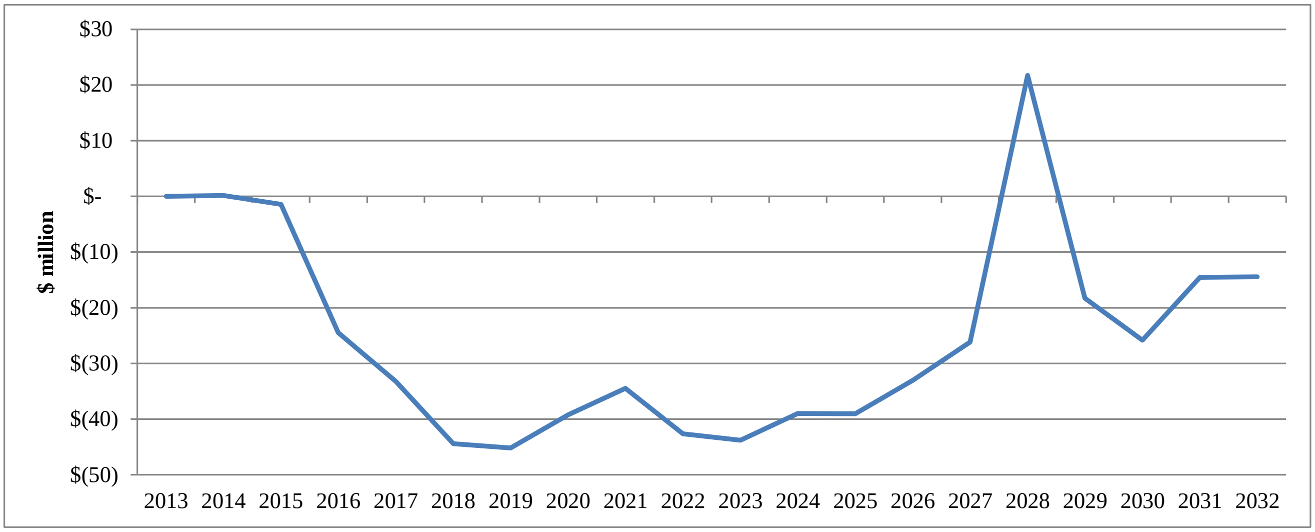
Using the PaR simulation results, the Company calculated the difference in the stochastic mean PVRR and the difference in the risk-adjusted PVRR per megawatt-hour (MWh) of wind generation removed from the EG2-C07 portfolio. Table 8.6 shows the change in the stochastic mean PVRR between the two portfolios, the change in the risk-adjusted net PVRR between the two portfolios, and the associated first year real levelized change in system costs per megawatt-hour of wind removed. Results are provided for each CO_2 price scenario.

Table 8.6 – Impact of Washington Situs Assigned Wind Generation Resources

	Stochastic Mean PVRR		Risk-Adjusted PVRR	
	Reduction in System PVRR with Removal of Wind ($m)	**Real Levelized Reduction System PVRR per MWh of Wind Removed ($/MWh)**	**Reduction in System PVRR with Removal of Wind ($m)**	**Real Levelized Reduction System PVRR per MWh of Wind Removed ($/MWh)**
Zero CO_2	243	61	232	59
Medium CO_2	200	51	189	48
High CO_2	132	33	116	29

The stochastic mean results above demonstrate that use of unbundled renewable energy credits (REC) at prices at or below the range of $33/MWh to $61/MWh, depending upon the CO_2 price scenario, is a lower cost compliance alternative to adding wind resources to the system as a means to achieve compliance with Washington RPS requirements. When accounting for risk, using the risk-adjusted PVRR metric, the range in unbundled REC prices required to achieve a lower cost compliance alternative to meeting Washington RPS requirements is slightly lower than the stochastic mean results, but still significantly higher than currently observed unbundled REC prices. The results above also suggest that REC prices would need to be in the range of $29/MWh to $61/MWh, depending upon CO_2 price assumptions and risk profile, for wind resources to be cost-effective given current policy and market conditions. With current unbundled REC prices trading at approximately $1/MWh, the Company has selected portfolio EG2-C07a as the 2013 IRP preferred portfolio. Figure 8.27 compares the change in nominal revenue requirement between the EG2-C07a and EG2-C07 portfolios. The spike observed in 2028 is driven by the acceleration of Class 1 DSM resources by one year in the case where wind is removed from the EG2-C07 portfolio.

Figure 8.27 – Increase/(Decrease) in Annual Nominal Revenue Requirement with Wind Removed from the EG2-C07 Portfolio



The 2013 IRP Preferred Portfolio

Summary Reports

The following tables and figures summarize the 2013 IRP preferred portfolio:

- Table 8.7 shows the nameplate capacity of resources in the preferred portfolio over the 2013 through 2032 planning period.

- Table 8.8 shows the load and resource balance inclusive of preferred portfolio resources for the first 10 years of the planning horizon.

- Figures 8.28 and 8.29 present the capacity and energy resource mix, respectively, for representative years 2013 and 2022.
  - In the case where the resource type for a purchased power contract is identifiable, the contract is included with the corresponding resource group.
  - Energy mix figures are based upon medium natural gas, power, and CO2 price assumptions.
  - As noted in Chapter 3, the renewable energy capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.

- Figure 8.30 graphically shows how PacifiCorp's capacity deficit is met through existing and IRP preferred portfolio resources.

- Figure 8.31 shows the contribution of energy from preferred portfolio resources to load growth projections from 2013 levels.

- Table 8.9 shows the amount of energy from Class 2 DSM resources by state.

Table 8.7 – PacifiCorp's 2013 IRP Preferred Portfolio

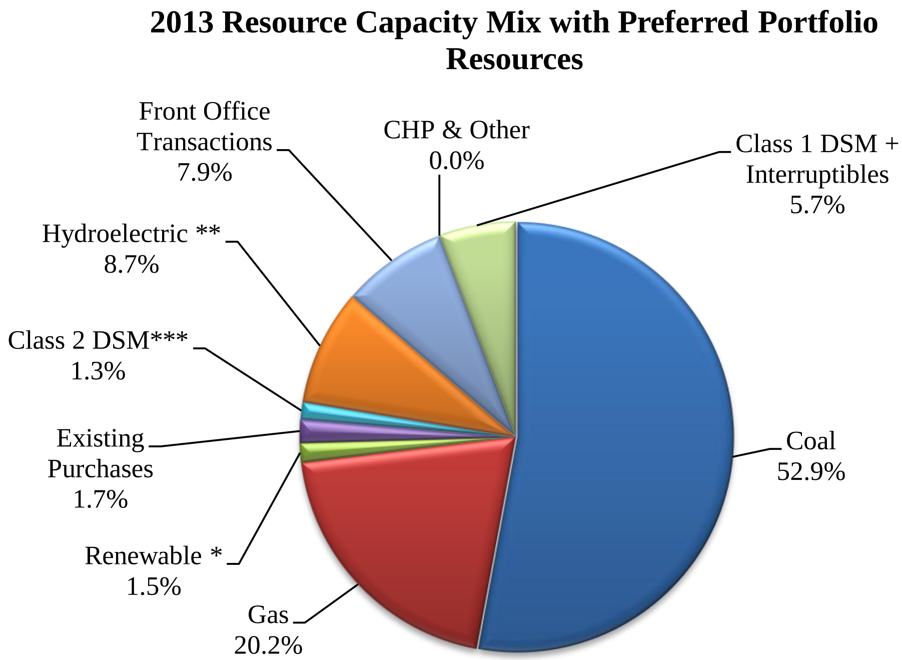
	Preferred Portfolio (EG-2 Case-07a)	Capacity (MW) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Resource Totals 1/ 10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	88
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	19	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	19	88	-	-	-	-	121
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	63	61	54	52	50	48	48	43	42	40	30	33	30	28	27	26	24	22	21	20	500	760
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	127
	DSM, Class 2 Total	69	67	61	60	59	57	58	52	52	51	39	42	39	38	37	36	34	32	31	30	587	946
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	37	151	248	19	161	255	-	132	253	297	292	300	59	109	74	62	119
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	23	23	22	22	23	26	26	24	19	22	22	288	517
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	30	28	28	28	29	32	30	29	23	26	26	368	647
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	262	297	297	297	297	297	297	297	237	297	297	297	297	297	297	297	297	255	273
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	119	116	106	104	95	96	98	84	942	302	84	171	944	167	1,155	73	254		
	Annual Additions, Short Term Resources	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246		
	Total Annual Additions	791	1,486	966	1,102	1,218	1,315	1,427	1,515	1,287	1,431	1,511	2,054	1,606	1,509	1,640	2,408	1,639	2,386	1,354	1,500		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

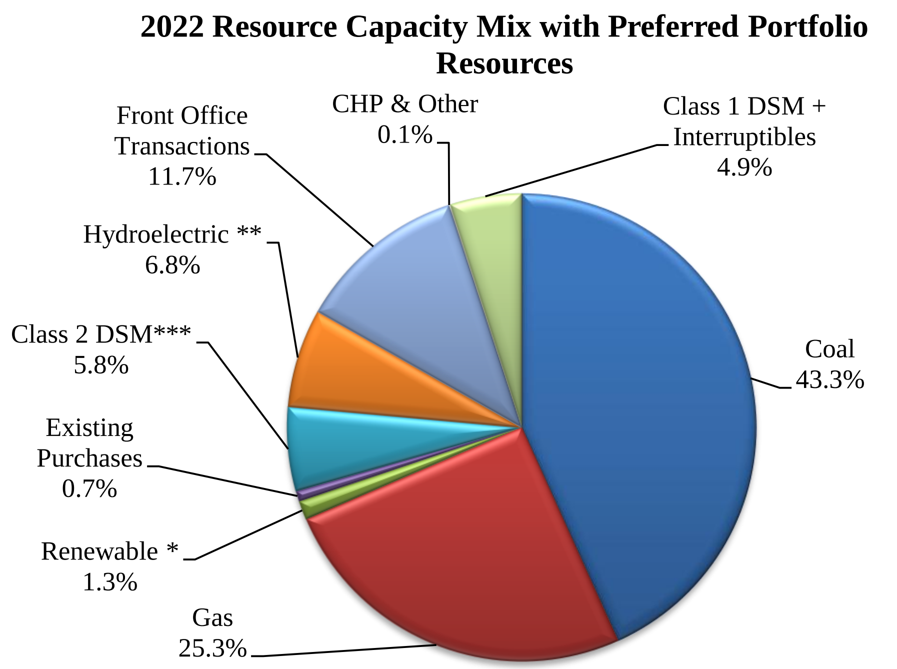
Table 8.8 – Preferred Portfolio Capacity Load and Resource Balance (2013-2022)

Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
East										
Thermal	6,200	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	137	140	140	135	135	132	135	135	135	135
Renewable	85	85	83	83	83	83	83	83	82	80
Purchase	1,005	611	611	398	285	285	285	285	257	257
Qualifying Facilities	83	73	73	73	73	73	73	73	73	25
Sale	(1,032)	(732)	(730)	(724)	(638)	(638)	(638)	(639)	(158)	(158)
Non-Owned Reserves	(103)	(103)	(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)
Transfers	804	574	847	791	890	924	871	850	754	726
East Existing Resources	**7,179**	**7,274**	**7,346**	**7,072**	**7,144**	**7,175**	**7,125**	**7,103**	**7,459**	**7,381**
Combined heat and Power	0	0	1	3	3	3	3	4	4	6
Front Office Transactions	0	0	0	0	0	41	170	280	22	181
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	1	2	3	4	5	5	6	7	8
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**1**	**3**	**6**	**7**	**49**	**178**	**290**	**33**	**195**
East Total Resources	**7,179**	**7,275**	**7,349**	**7,078**	**7,151**	**7,224**	**7,303**	**7,393**	**7,492**	**7,576**
Load	6,920	7,061	7,188	6,994	7,105	7,217	7,337	7,455	7,584	7,697
Existing Resources:										
Interruptible	(141)	(143)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
DSM	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(55)	(109)	(160)	(208)	(255)	(302)	(350)	(389)	(430)	(466)
East obligation	**6,345**	**6,430**	**6,494**	**6,252**	**6,316**	**6,381**	**6,453**	**6,532**	**6,620**	**6,697**
Planning Reserves (13%)	825	836	844	813	821	830	839	849	861	871
East Reserves	**825**	**836**	**844**	**813**	**821**	**830**	**839**	**849**	**861**	**871**
East Obligation + Reserves	**7,170**	**7,266**	**7,338**	**7,065**	**7,137**	**7,211**	**7,292**	**7,381**	**7,481**	**7,568**
East Position	**9**	**9**	**11**	**13**	**14**	**13**	**11**	**12**	**11**	**8**
East Reserve Margin	13.1%	13.1%	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%	13.1%
West										
Thermal	2,524	2,524	2,524	2,520	2,503	2,503	2,503	2,503	2,503	2,500
Hydroelectric	776	751	776	782	780	780	723	726	647	650
Renewable	36	36	36	36	36	36	36	36	36	19
Purchase	482	225	231	13	13	13	2	2	2	2
Qualifying Facilities	88	99	99	89	89	89	88	89	89	89
Sale	(260)	(260)	(160)	(110)	(110)	(110)	(110)	(110)	(109)	(103)
Non-Owned Reserves	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Transfers	(804)	(574)	(848)	(792)	(890)	(924)	(872)	(851)	(754)	(727)
West Existing Resources	**2,833**	**2,792**	**2,649**	**2,529**	**2,412**	**2,378**	**2,361**	**2,386**	**2,405**	**2,421**
Combined heat and Power	1	1	2	2	3	3	4	4	5	6
Front Office Transactions	734	800	954	1,110	1,246	1,325	1,325	1,325	1,325	1,325
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**735**	**801**	**956**	**1,112**	**1,249**	**1,328**	**1,329**	**1,329**	**1,330**	**1,331**
West Total Resources	**3,568**	**3,593**	**3,605**	**3,641**	**3,661**	**3,706**	**3,690**	**3,715**	**3,735**	**3,752**
Load	3,216	3,269	3,307	3,365	3,407	3,470	3,479	3,516	3,549	3,583
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(26)	(62)	(86)	(113)	(139)	(161)	(183)	(197)	(217)	(235)
West obligation	**3,162**	**3,179**	**3,193**	**3,224**	**3,240**	**3,281**	**3,268**	**3,291**	**3,304**	**3,320**
Planning Reserves (13%)	411	413	415	419	421	427	425	428	430	432
West Reserves	**411**	**413**	**415**	**419**	**421**	**427**	**425**	**428**	**430**	**432**
West Obligation + Reserves	**3,573**	**3,592**	**3,608**	**3,643**	**3,661**	**3,708**	**3,693**	**3,719**	**3,734**	**3,752**
West Position	**(5)**	**1**	**(3)**	**(2)**	**(0)**	**(2)**	**(3)**	**(4)**	**1**	**0**
West Reserve Margin	12.8%	13.0%	12.9%	12.9%	13.0%	13.0%	12.9%	12.9%	13.0%	13.0%
System										
Total Resources	10,747	10,868	10,954	10,719	10,812	10,930	10,993	11,108	11,227	11,328
Obligation	9,507	9,609	9,687	9,476	9,556	9,662	9,721	9,823	9,924	10,017
Reserves	1,236	1,249	1,259	1,232	1,242	1,256	1,264	1,277	1,290	1,302
Obligation + Reserves	10,743	10,858	10,946	10,708	10,798	10,918	10,985	11,100	11,214	11,319
System Position	4	10	8	11	14	12	8	8	13	9
Reserve Margin	13.0%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%	13.1%

Figure 8.28 – Current and Projected PacifiCorp Resource Capacity Mix for 2013 and 2022

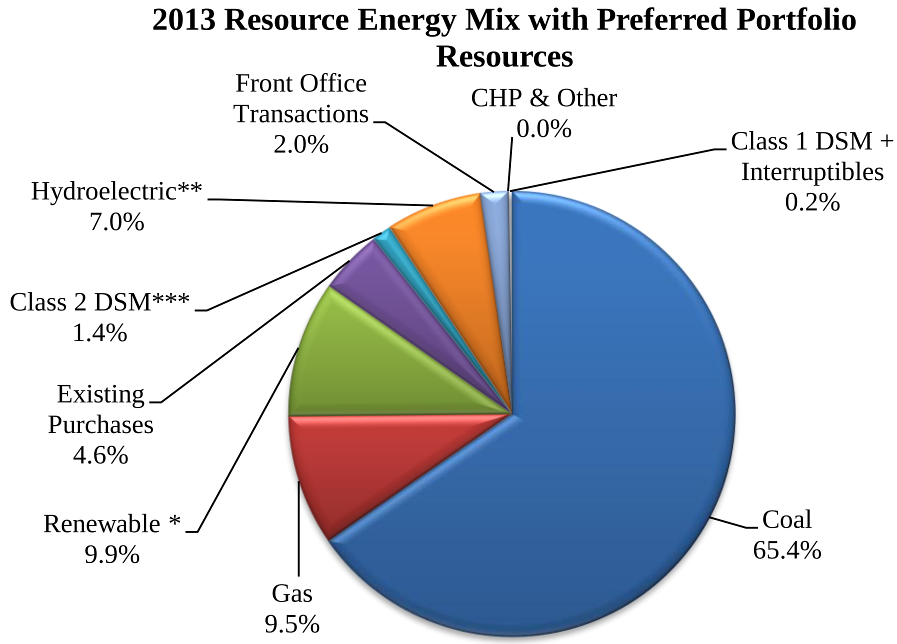


* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.
*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

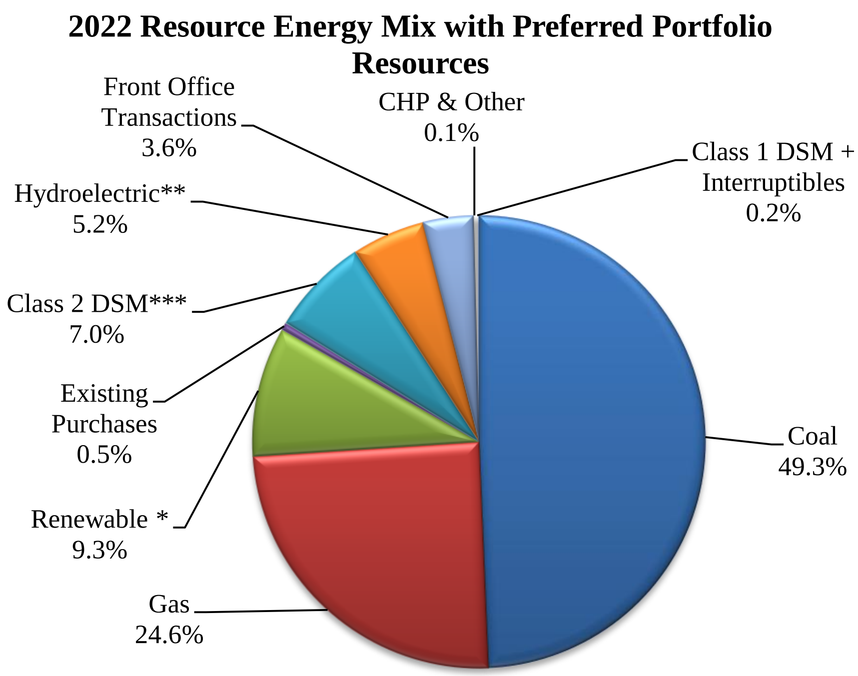


* Renewable resources include wind, solar and geothermal. Wind capacity is reported as the peak load contribution.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.
*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

Figure 8.29 – Current and Projected PacifiCorp Resource Energy Mix for 2013 and 2022

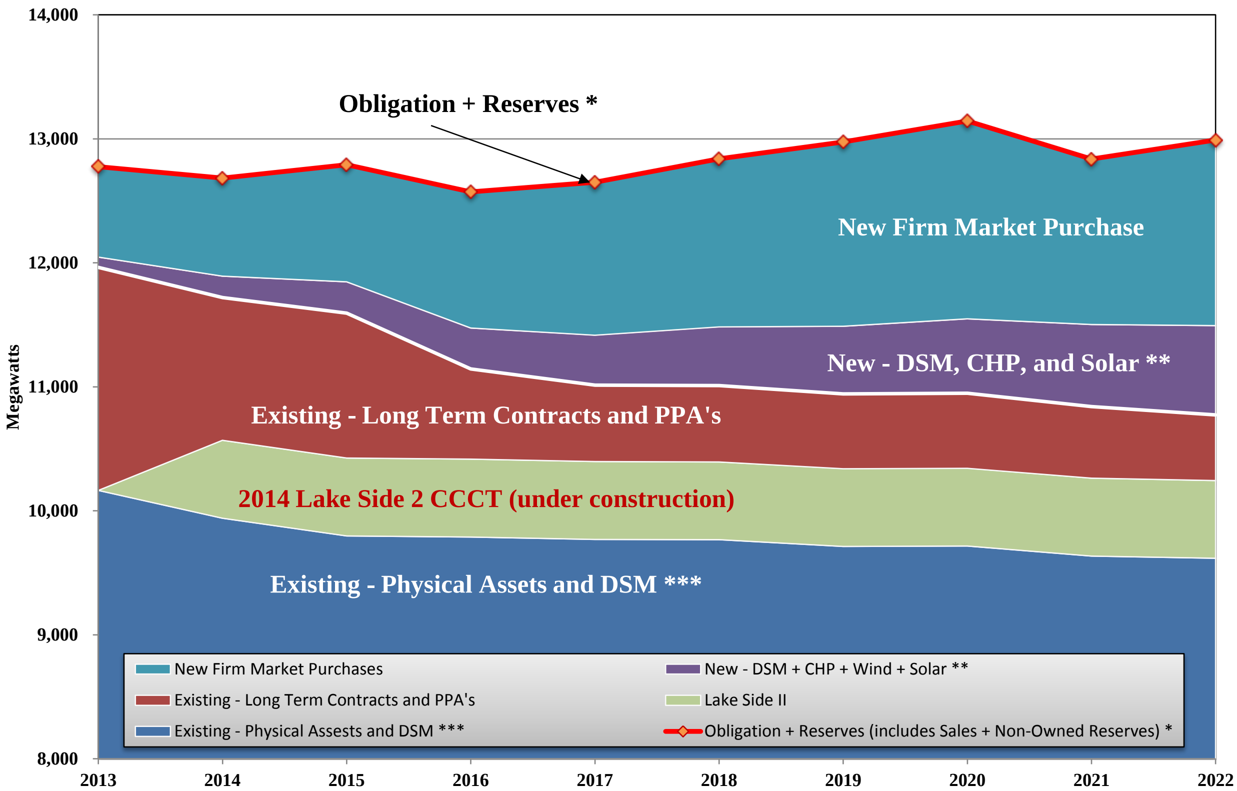


* Renewable resources include wind, solar and geothermal.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.
*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.



* Renewable resources include wind, solar and geothermal.
** Hydroelectric resouces include owned, qualifying facilities and contract purchases.
*** The contribution of Class 2 DSM represents incremental acquisition of DSM resources over the planning period.

Figure 8.30 – Addressing PacifiCorp's Peak Capacity Deficit, 2013 through 2022



* Includes 13% Planning Reserves, Sales and Non-Owned Reserves
** Solar resources peak contribution is 8 MW by 2022 and Combined Heat and Power (CHP) contributes 12 MW.
*** Includes retirements, turbine upgrades, and gas repower. DSM includes both Class 1 and 2.

Figure 8.31 – Energy Contribution of the Preferred Portfolio Resources to Load Growth, PacifiCorp System (2013-2022)

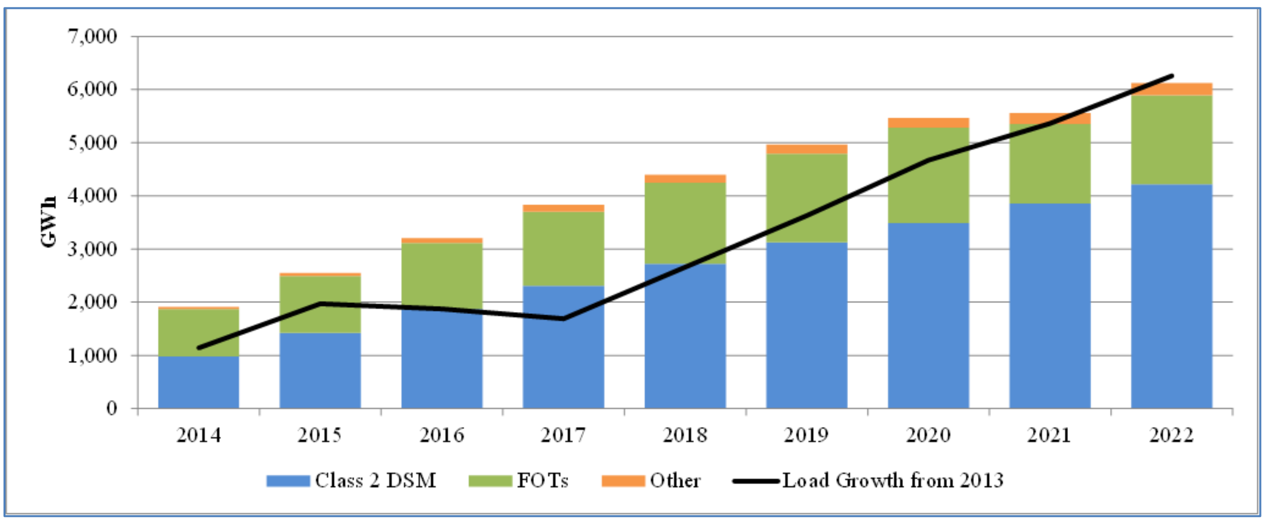


Table 8.9 – Preferred Portfolio Demand Side Management Energy (2013-2022)

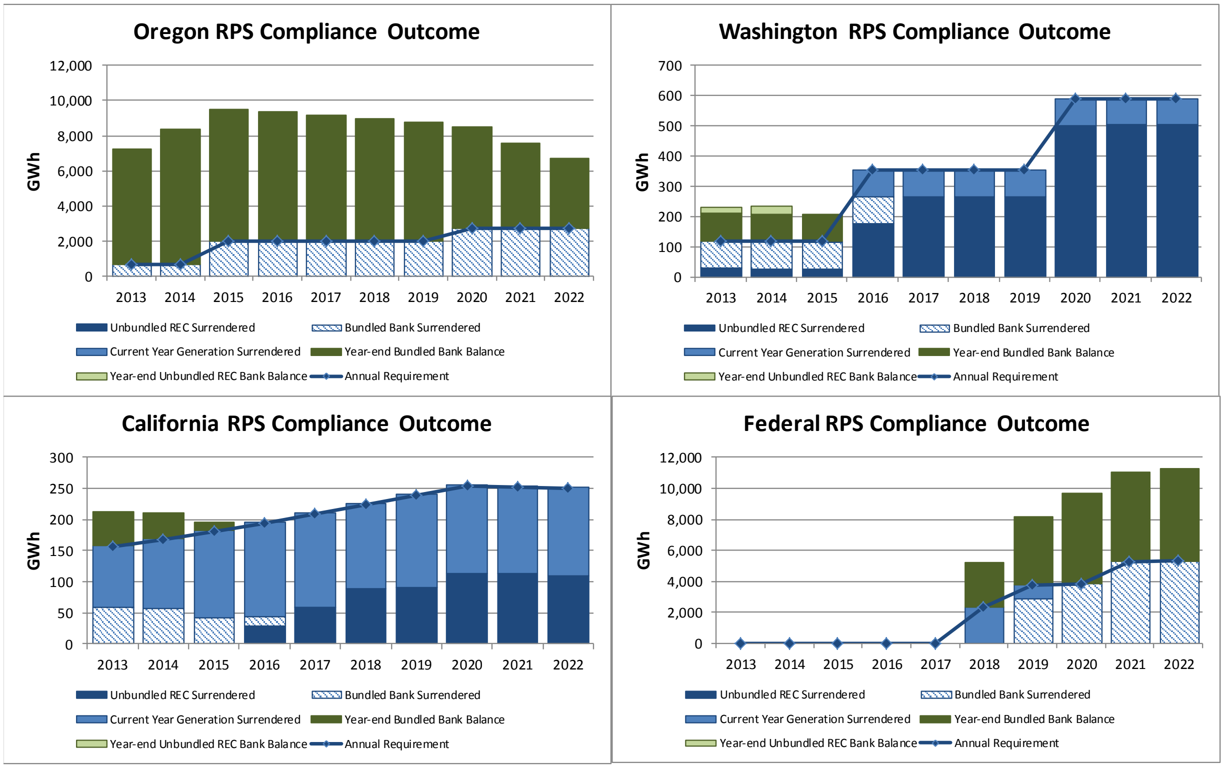
Energy Efficiency Energy (MWh) Selected by State and Year										
State	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CA	4,850	4,980	5,500	5,450	5,560	4,680	4,450	4,300	4,730	4,890
OR	168,040	188,540	148,170	145,020	132,770	126,240	108,870	95,900	91,270	99,140
WA	38,200	36,600	36,430	36,740	36,520	30,640	30,530	28,520	28,330	28,630
UT	234,790	224,220	209,570	208,410	203,540	196,600	202,440	174,740	171,900	165,400
ID	10,690	11,090	11,470	12,010	13,540	13,060	14,560	13,770	14,350	14,740
WY	26,850	30,530	34,740	38,680	42,090	43,810	45,250	45,610	50,000	52,840
Total System	483,420	495,960	445,880	446,310	434,020	415,030	406,100	362,840	360,580	365,640
Cumulative	483,420	979,380	1,425,260	1,871,570	2,305,590	2,720,620	3,126,720	3,489,560	3,850,140	4,215,780

Preferred Portfolio Compliance with Renewable Portfolio Standard Requirements

Figure 8.32 shows PacifiCorp's forecasted RPS compliance positions for the California, Oregon, and Washington[78] programs, along with a federal RPS program scenario[79], covering the period 2013 through 2022 based on the preferred portfolio. Utah's RPS goal is tied to a 2025 compliance date, so the 2013-2022 position is not shown below. However, PacifiCorp meets the Utah 2025 state target of 20 percent based on eligible Utah RPS resources, and has significant levels of banked RECs to sustain continued future compliance. PacifiCorp anticipates utilizing flexible compliance mechanisms such as banking the use of unbundled RECs as allowed in each state.

[78] The Washington RPS requirement is tied to January 1st of the compliance year.
[79] The assumed federal RPS requirements are applied to retail sales, with a target of 4.5 percent beginning in 2018, 7.1 percent in 2019-2020, 9.8 percent in 2021-2022, 12.4 percent in 2023-2024, and 20 percent in 2025.

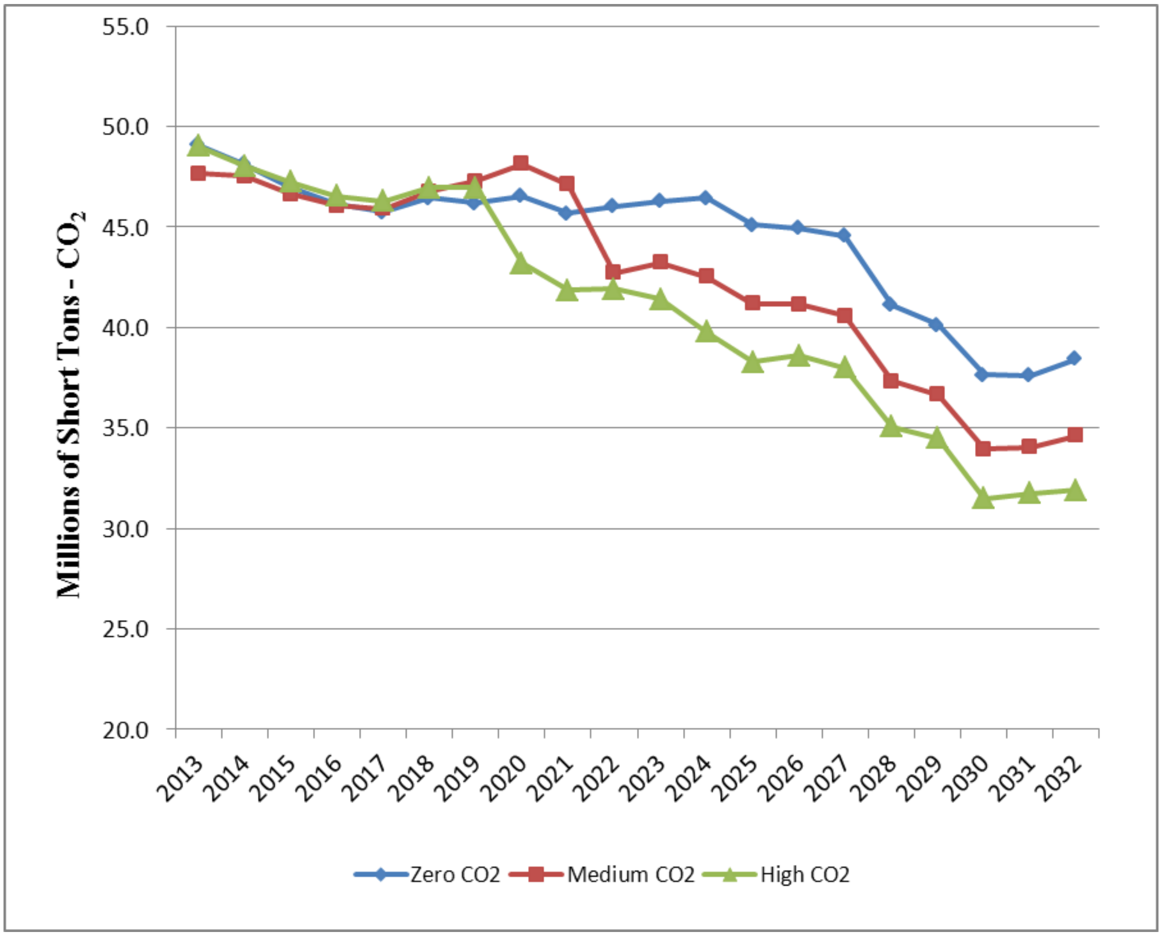
Figure 8.32 – Annual State and Federal RPS Position Forecasts using the Preferred Portfolio



Preferred Portfolio Carbon Dioxide Emissions

Cumulative CO_2 emissions by 2032 for the preferred portfolio under the three CO_2 price scenarios range from 819 million tons to 889 million tons. These emission quantities are reported by the PaR model. Regarding CO_2 emission reduction trends, near-term reductions are driven by plant dispatch changes in response to assumed CO_2 costs. In the longer term, accumulated addition of energy efficiency programs, renewable resources, as well as new gas-fired resources that fill resource needs with assumed end-of-life coal resource retirements contribute to a downward trend in emission levels. Figure 8.33 illustrates the emission trends for the preferred portfolio through 2032 under the zero, medium and high CO_2 price scenarios.

Figure 8.33 – Carbon Dioxide Emission Trend



Sensitivity Analyses

System Optimizer Sensitivity Cases

As described in Chapter 7, sensitivity cases focus on changes to resource-specific assumptions and alternative load growth forecasts. PacifiCorp developed 12 sensitivity cases aligned with the themes used to develop core case portfolios. The sensitivity case themes cover load sensitivities, targeted resource sensitivities, and environmental policy sensitivities, which are described in Confidential Volume III of this IRP report. Sensitivity cases are variants from the System Optimizer portfolios developed under core case definitions. Each sensitivity case was completed under Energy Gateway Scenario 2.

Figure 8.34 shows the cumulative capacity additions by resource type for each of the sensitivity case portfolios in 2032, the end of the 2013 IRP planning horizon. For comparison, portfolios from core case C03 and the preferred portfolio C07a are also included in the figure. Table 8.10 lists the system costs from the System Optimizer model for each of the sensitivity cases, core case C03, and the preferred portfolio (case C07a). The detailed portfolio resource tables are included in Volume II, Appendix K, along with detailed System Optimizer PVRR results.

Figure 8.34– Total Cumulative Capacity of Sensitivity Cases, 2032

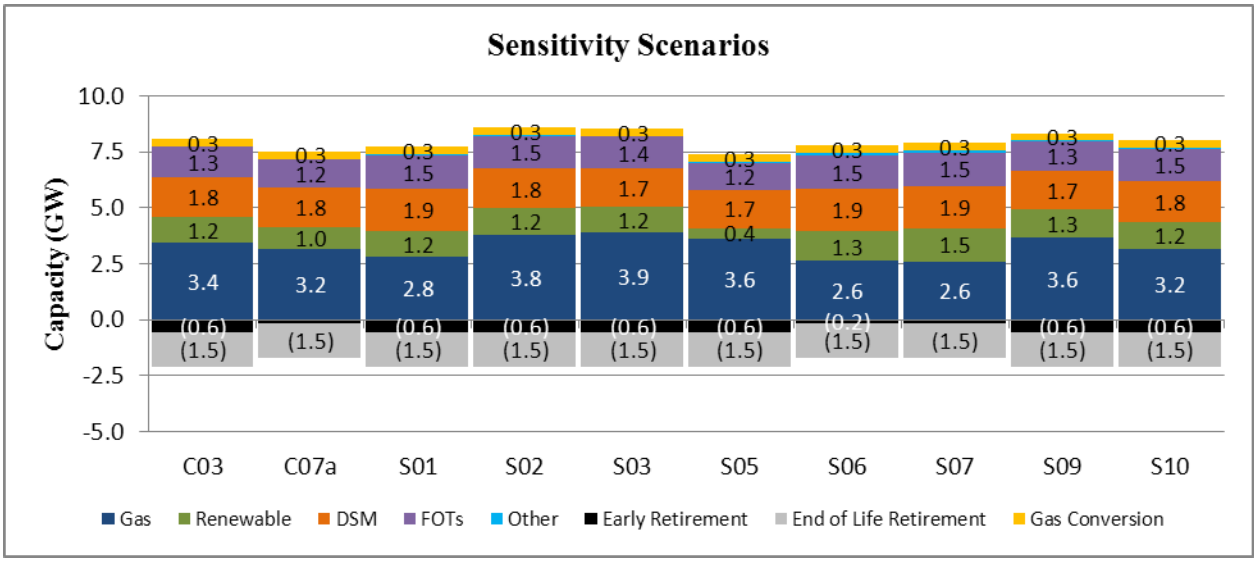


Table 8.10 – PVRR of Sensitivity Cases and the Comparative Core Cases

Case	PVRR ($m)
C01	$31,237
C03	$31,584
Preferred Portfolio (C-07a)	$27,347
S01	$30,656
S02	$33,129
S03	$31,978
S05	$31,237
S06	$31,485
S07	$31,603
S09	$38,996
S10	$31,586

Load Sensitivities (S01, S02, and S03)

PacifiCorp conducted three System Optimizer runs for three alternative load growth scenarios: low load growth (case S01), high load growth (case S02), and 1-in-20 extreme system peak scenario (case S03). Figures 8.35 and 8.36 show how coincident peak and system load forecasts in these sensitivities compare to the base load forecast used to define core cases.

Figure 8.35 – Sensitivity Case Coincidental Peak Load Forecasts

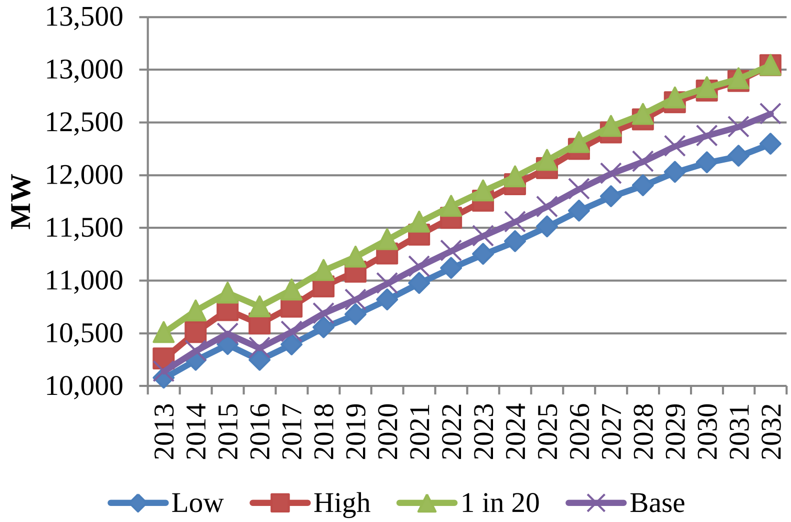
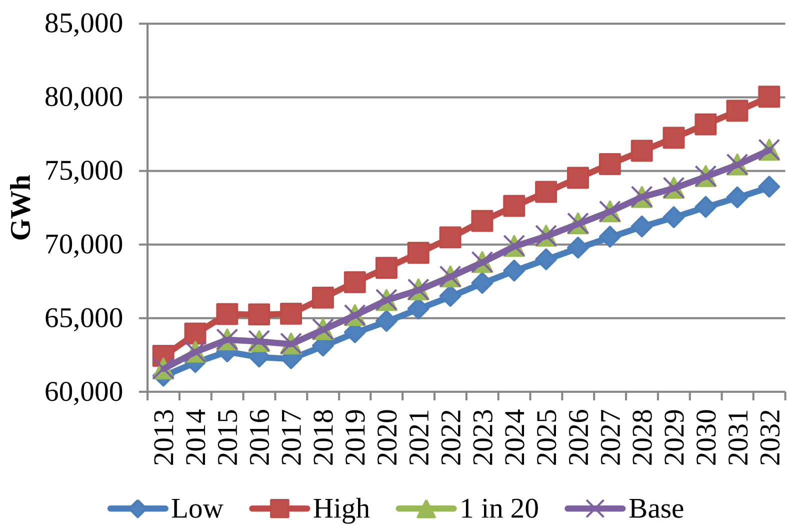


Figure 8.36 – Sensitivity Case Load Forecasts



Under the low load forecast sensitivity, the 2024 CCCT that is in the preferred portfolio is replaced with peaking gas resources added in 2025 and 2026. Similarly, a 2028 CCCT is replaced with a peaking resource in 2029. Under the high load forecast sensitivity, incremental FOTs and DSM meet higher loads through 2018 and a west side 203 MW frame peaking resource is added to the portfolio in 2019. Under the 1-in-20 peak load forecast scenario, FOTs and DSM fill higher capacity requirements through 2017. The portfolio adds a west side 197 MW frame peaking unit in 2018 and an east side 181 MW frame peaking unit in 2020. In the out years (2028 and beyond), peaking units displace a 423 MW CCCT.

Extension of PTC and ITC (S05 and S06)

For this group of sensitivity cases, federal production tax credits (PTCs) and investment tax credits (ITCs) are extended through the end of 2019. Case S05 assumes no RPS requirements and case S06 assumes both state and federal RPS requirements must be met.

Absent RPS assumptions, the extension of the PTC/ITC assumption leads to 144 MW of Wyoming wind in in 2019 (the last year of the extension). With RPS requirements, 2019 wind additions total 500 MW more than in the base case. Figures 8.37 and 8.38 show the addition of wind resources in the two cases. Case S05 wind additions are shown alongside wind additions in the reference case C01 portfolio, which similarly does not include RPS assumptions.

Figure 8.37 – Cumulative Wind Additions, No RPS

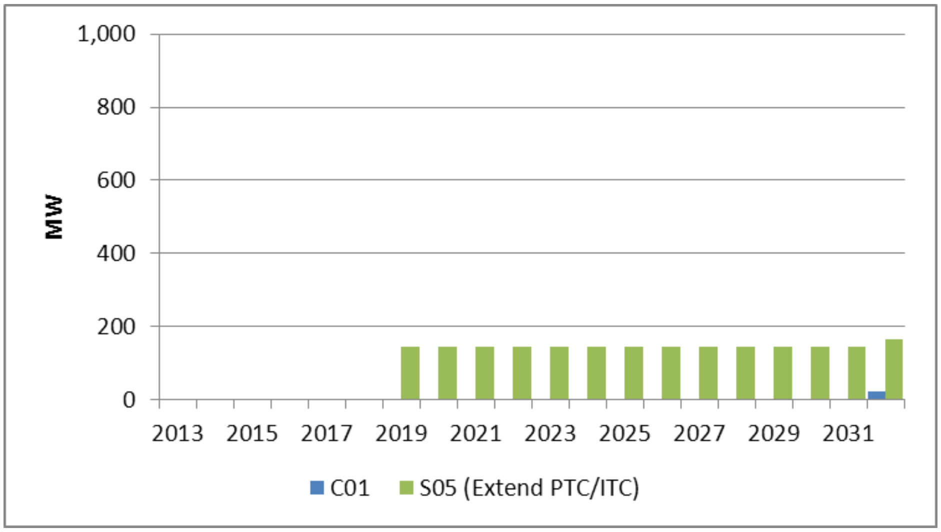
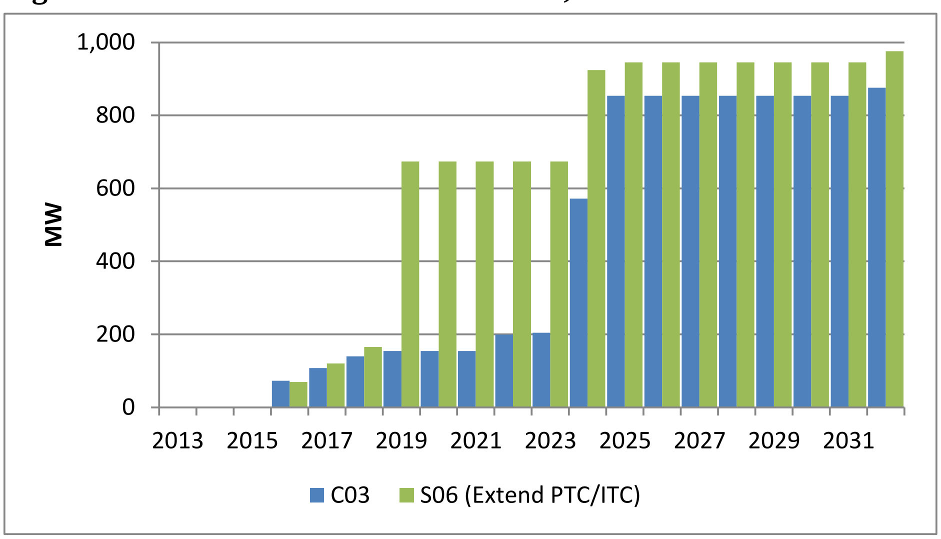


Figure 8.38 – Cumulative Wind Addition, with RPS



Endogenous Selection of Resources to Meet RPS Requirements (S07)

In this case, instead of using the RPS Scenario Maker model to select renewable resources based on state-specific requirements, the resource selections needed to meet RPS requirements were modeled endogenously in the System Optimizer model.

Case S07 produced more renewable capacity at different times and in different locations, and produced system costs that are approximately $20 million higher than those from case C03. Because the System Optimizer model cannot capture state specific rules, none of the resources, with the exception of the Oregon Geothermal PPA, selected in 2026 could satisfy the Washington requirement that resources be in the Pacific Northwest.[80] Moreover, there is no objective way to assign generation from resources that were added to meet a “system” RPS requirement back to the specific state to ensure that RPS compliance is achieved in each state.

Table 8.11 compares the renewable resources selected in case S07 with the ones selected by the RPS Scenario Maker model for case C03.

Table 8.11 – Renewable Resources in Case S07 and Case C03

Renewable resource selected in S07:

Resource	Assigned	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
WY Wind (40% CF)	System	0	0	0	1	74	0	0	0	0	0	539	26	0	0	9	0	0	649
UT Wind (29% CF)	System	0	18	12	0	0	0	0	0	16	0	74	0	0	0	0	7	72	199
UT Utility Scale Solar	System	100	0	0	0	0	0	0	0	0	0	0	0	0	0	100	0	0	200
OR Geothermal PPA	System	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	30
Total		100	18	12	1	74	0	0	0	16	0	643	26	0	0	109	7	72	1078

Renewable resource selected in C03:

Resource	Assigned	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
WY Wind (40% CF)	System	0	0	0	0	0	0	0	0	368	282	0	0	0	0	0	0	0	650
UT Wind (29% CF)	System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	22
ID Wind (29% CF)	WA	73	34	33	14	0	0	45	5	0	0	0	0	0	0	0	0	0	204
Total		73	34	33	14	0	0	45	5	368	282	0	0	0	0	0	0	22	876

2013 Business Plan Portfolio (S08)

This sensitivity case was intended to test the impact of PacifiCorp’s 2013 Business Plan resource portfolio in the 2013 IRP modeling environment. However, the changes and updates in the System Optimizer model since the 2013 Business Plan study made it difficult to enforce and merge the previously selected portfolio with the new model inputs. Specifically, Class 2 DSM resources are configured in more detail as compared to what was used to develop the 2013 Business Plan portfolio. It is not practical to reconstruct the previous representation of DSM resources in a way that is compatible with the current modeling system. Consequently, PacifiCorp did not complete this sensitivity case for the 2013 IRP. For comparison purposes, categories of resources in the 2013 Business Plan resource portfolio are shown in Table 8.12.

[80] Legislation has since been passed in Washington that removes the Pacific Northwest geographic requirement. However, the point remains valid, which is the System Optimizer model does not capture state-specific RPS rules in selecting renewable resources needed to meet RPS requirements.

Table 8.12 – 2013 Business Plan Resource Portfolio

	Capacity (MW)											Resource Totals
Resource	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2013-2022
Coal Plant Turbine Upgrades	19	14	-	-	-	-	-	-	-	-	-	**14**
Gas	-	-	638	-	-	-	-	-	-	-	-	**638**
Wind	-	-	-	-	-	-	100	100	100	100	-	**400**
Other Renewables / Solar	4	4	3	3	-	-	-	-	-	-	-	**10**
DSM, Class 1	-	-	-	-	-	-	-	1	100	-	-	**101**
DSM, Class 2	101	86	90	95	93	90	95	97	100	104	110	**960**
Distributed Generation	5	5	5	5	5	5	5	5	5	5	5	**52**
Total Long Term Resources	**130**	**109**	**736**	**104**	**98**	**95**	**201**	**202**	**305**	**210**	**115**	**2,174**
Utah Capacity Purchase *	200	200	-	-	200	200	200	200	200	-	-	120
East - Firm Market Purchases	62	-	92	51	88	72	130	246	300	81	143	120
West - Firm Market Purchases	1,055	918	875	1,078	1,029	1,168	1,217	1,217	1,217	1,217	1,217	1,115
Firm Market Purchases	**1,317**	**1,118**	**967**	**1,128**	**1,318**	**1,440**	**1,546**	**1,662**	**1,717**	**1,297**	**1,360**	**1,355**

Study includes Naughton 3 gas conversion in 2015
FOT in resource total are 10-year averages

Resurgence of Renewable Resources (S09)

This sensitivity was designed to target additional selection of renewable resources with high natural gas price and high CO_2 price assumptions while assuming PTCs and ITCs are extended through 2019. As compared with sensitivity case S06, which shares the same input assumptions, but for the use of medium natural gas price and CO_2 prices, the case S09 portfolio did not include additional renewable resources.

Class 3 DSM (S10)

For this sensitivity case, 15 MW of Class 3 DSM resources were added as potential resources in addition to Class 1 DSM resource alternatives. Based on resource needs and economics, 10 MW of the potential Class 3 DSM resource were selected, primarily in 2027, 2031 and 2032, with minimal impact on System Optimizer system costs.

Additional Analysis

Trigger Point Analysis

The Oregon Public Utility Commission (OPUC) guideline 8(c) requires the utility to identify at least one portfolio of resources that is substantially different from the preferred portfolio that can be compared on a risk and cost basis among a range of CO_2 compliance scenarios. As discussed earlier in this chapter, there are several portfolios evaluated across a range of CO_2 emission compliance scenarios that yield extensive coal unit retirements. This includes portfolios developed under cases C05, C09, C14 and C18. Table 8.13 below compares the stochastic mean and risk-adjusted PVRR of these portfolios under Energy Gateway Scenario 2 to the preferred portfolio.

Table 8.13 – Comparison of Trigger Point Portfolios to the Preferred Portfolio

	Zero CO_2		Medium CO_2		High CO_2	
Core Case	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)
C05	3.17	7.17	2.54	7.97	1.42	9.06
C09	4.09	8.47	3.59	9.46	2.33	10.55
C14	2.68	5.88	2.03	6.53	0.97	7.53
C18	7.04	0.83	6.48	0.50	5.51	(0.25)

In each of these cases, the resulting portfolios were developed assuming either high or U.S. hard cap CO_2 price assumptions. Policy makers have not succeeded in passing federal greenhouse gas legislation for consideration by the President. While the U.S. Environmental Protection Agency (EPA) has proposed new source performance standards to regulate greenhouse gas emissions from new sources, it has not finalized those standards, nor has it established a schedule to promulgate rules applicable to existing sources. Concurrently, policy makers continue to debate Federal budget deficits, and deep philosophical differences have thus far proven to be a barrier to budgetary compromise. Given these considerations, the Company does not believe greenhouse gas policies or regulations will be mandated at the levels and on a schedule that contributed to the extensive level of early coal unit retirements and gas conversions observed in the cases summarized in the table above.

Oregon Greenhouse Gas Goals

The OPUC guideline 8(d) requires that a portfolio be constructed that meets state of Oregon energy policies, including state goals for reducing greenhouse emissions. Several of the portfolios developed in this IRP fall below the Oregon goal stated in House Bill 3543 (10 percent below 1990 emission levels by 2020). For PacifiCorp's system, the 1990 emission level was 49.88 million short tons, and 10 percent below this level is 44.89 million short tons. Table 8.13 compares the preferred portfolio with portfolios developed for Energy Gateway Scenario 2 that are in compliance with the emission reduction goal in Oregon.

Table 8.13 – Cost/Risk Comparison of Compliance Portfolios and the Preferred Portfolio, with Medium CO_2 Prices

Case	Stochastic Mean PVRR	Upper Tail Mean PVRR	Emissions in 2020 Thousands of Ton
EG1-C04	33,507	46,307	34,868
EG1-C05	34,035	46,056	34,695
EG1-C08	34,378	48,397	26,999
EG1-C09	35,009	48,382	26,852
EG1-C14	33,401	44,056	36,811
EG2-C04	33,554	46,234	34,955
EG2-C05	33,898	45,965	34,802
EG2-C07a	31,357	35,452	48,124
EG2-C08	34,548	48,357	27,273
EG2-C09	34,944	48,502	27,239
EG2-C14	33,384	44,013	36,934

CHAPTER 9 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2013 IRP action plan identifies steps to be taken during the next two to four years to implement the IRP. The preferred portfolio reflects a snapshot view of the future that accounts for a wide range of uncertainties, and is not intended as a procurement commitment.
- Achieve renewable compliance with unbundled renewable energy credit purchases.
- Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity.
- Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017
- Continue to pursue the Energy Imbalance Market activities in California and the Northwest Power Pool
- Manage and improve the longer term natural gas hedging process and products, and continue to work with stakeholders.
- Acquire up to 1,425 – 1,876 GWh of cost effective Class 2 energy efficiency by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017.
- Develop a pilot program in Oregon for Class 3 time-of-use program as an alternative approach to Class 1 irrigation load control program for managing irrigation load in the west.
- Continue to permit and develop the Naughton Unit 3 natural gas conversion project.
- Complete the installation of the baghouse conversion and NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014.
- Complete the installation of selective catalytic reduction compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4.
- Evaluate alternative compliance strategies that will meet Regional Haze compliance obligations for Cholla Unit 4.
- Establish a stakeholder group process to review the System Operational and Reliability Benefits Tool (SBT).
- Complete the Sigurd to Red Butte 345kV transmission line according to the construction plan.
- Evaluate through the resource acquisition paths, the fundamentals-based shifts in environmental policy, enactment of regulatory policies, and different load trajectories.
- Continue to use competitive solicitation processes and pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers.

Introduction

PacifiCorp's 2013 IRP action plan identifies the steps the Company will take during the next two to four years to implement the plan that covers the 10 year resource acquisition time frame, 2013-2022. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time horizon that could materially impact resource acquisition strategies.

The resources included in the 2013 IRP preferred portfolio were used to help define the actions included in the action plan, focusing on the size, timing and type of resources needed to meet load obligations, and current and potential future state regulatory requirements. The preferred portfolio resource combination was determined to be the lowest cost on a risk-adjusted basis accounting for cost, risk, reliability, regulatory uncertainty and the long-run public interest.

The 2013 IRP action plan is based upon the latest and most accurate information available at the time of portfolio study. The Company recognizes that the preferred portfolio upon which the action plan is based reflects a snapshot view of the future that accounts for a wide range of uncertainties.

Resource information used in the 2013 IRP, such as capital and operating costs, incorporate the Company's most up to date cost information. However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition, and the evaluations will comply with then-current laws, regulatory rules and orders.

In addition to the action plan, progress on the prior action plan, and the acquisition path analysis, this chapter covers the following topics:

- Procurement delays
- IRP Action Plan linkage to the business plan
- Resource Procurement Strategy
- Assessment of owning assets vs. purchasing power
- Managing carbon risk for existing plants
- Purpose of hedging
- The treatment of customer and investor risks for resource planning

The Integrated Resource Plan Action Plan

The 2013 IRP action plan, detailed in Table 9.1, provides the Company with a road map for moving forward with new resource acquisitions.

The 2013 IRP Action Plan

The 2013 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2013 IRP process. Table 9.1 details specific 2013 IRP action items by category.

Table 9.1 – 2013 IRP Action Plan

Action Item	12. Renewable Resource Actions
1a.	**<u>Wind Integration</u>** • Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.
1b.	**<u>Renewable Portfolio Standard Compliance</u>** • With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations. – Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.
1c.	**<u>Renewable Energy Credit Optimization</u>** • On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.
1d.	**<u>Solar</u>** • Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the

	fourth quarter of 2013. • Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.
1e.	**<u>Capacity Contribution</u>** • Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.
Action Item	**13. Distributed Generation Actions**
2a.	**<u>Distributed Solar</u>** • Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.
2b.	**<u>Combined Heat & Power (CHP)</u>** • Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act (PURPA) Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp's system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.
Action Item	**14. Firm Market Purchase Actions**
3a.	**<u>Front Office Transactions</u>** • Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. – Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations. – Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.
Action Item	**15. Flexible Resource Actions**

4a.	**Energy Imbalance Market (EIM)** • Continue to pursue the EIM activities with the California Independent System Operator and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.
Action Item	**16. Hedging Actions**
5a.	**Natural Gas Request for Proposal** • Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company's process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.
Action Item	**17. Plant Efficiency Improvement Actions**
6a.	**Plant Efficiency Improvements** • Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. – By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. – Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures. – Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company's recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.
Action Item	**18. Demand Side Management (DSM) Actions**

7a.

Class 2 DSM

- Acquire 1,425 – 1,876 gigawatt hours (GWh) of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017.
  - Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact evaluation, assess further expansion of the program.
  - Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon.
    - Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013.
    - Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014.
    - Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.
  - Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio.
  - Increase acquisitions from business customers through prescriptive measures by expanding the “Trade Ally Network”.
    - Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013
  - Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1st quarter 2014.
  - Increase the reach and effectiveness of “express” or “typical” measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units.
    - Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013.
    - Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014.
    - Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.
  - Increase the reach of behavioral DSM programs:
    - Evaluate and expand the residential behavioral pilot.
      - Utah base case schedule is 2nd quarter 2014, with an accelerated target of 4th quarter 2013.
    - Accelerate commercial behavioral pilot to the end of the first quarter 2014.
    - Expand residential programs system-wide pending evaluation results.
      - System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014.
  - Increase acquisition of residential DSM resources:

	▪ Implement cost effective direct install options by the end of 2013. ▪ Expand offering of "bundled" measure incentives by the end of 2013. ▪ Increase qualifying measures by the end of 2013. ▪ Review and realign incentives. ♦ Utah schedule is 1st quarter 2014 ♦ Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014. ♦ Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014 – Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013. – By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required. – Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. – Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.

7b.	**<u>Class 3 DSM</u>** • Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and findings will be reported in the 2015 IRP.
Action Item	**19. Coal Resource Actions**
8a.	**<u>Naughton Unit 3</u>** • Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division. • Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process. • Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.
8b.	**<u>Hunter Unit 1</u>** • Complete installation of the baghouse conversion and low NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014.
8c.	**<u>Jim Bridger Units 3 and 4</u>** • Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.
8d.	**<u>Cholla Unit 4</u>** • Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.
Action Item	**20. Transmission Actions**
9a.	**<u>System Operational and Reliability Benefits Tool (SBT)</u>** • 60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). – For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment.

	– In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.
9b.	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. – Segment H Cascade Crossing, complete benefits analysis in 2013. – Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.
9c.	**<u>Sigurd to Red Butte 345 kilovolt Transmission Line</u>** • Complete project construction per plan.
Action Item	**21. Planning Reserve Margin Actions**
10a.	**<u>Planning Reserve Margin</u>** • Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.
Action Item	**22. Planning and Modeling Process Improvement Actions**
11a.	**<u>Modeling and Process</u>** • Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process improvements in the 2015 IRP.
11b.	**<u>Cost/Benefit Analysis of DSM Resource Alternatives</u>** • Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2011 Integrated Resource Plan Update report filed with the state commissions on March 31, 2011. Many of these action items have been superseded in some form by items identified in the current IRP action plan.

Action Item 1: Renewable / Distributed Generation 2021-2020

- Acquire up to 800 MW of wind resources by 2020, dictated by regulatory and market developments such as (1) renewable/clean energy standards; (2) carbon regulations; (3) federal tax incentives; (4) economics; (5) natural gas price forecasts; (6) regulatory support for investments necessary to integrate variable energy resources (VERs); and (7) transmission developments. The 800 MW level is supported by consideration of regulatory compliance risks and public policy interest in clean energy resources.
- In the 2013 IRP, PacifiCorp will track and report the statistics used to calculate capacity contribution from its wind resources as a means of testing the validity of the PLCC method.
- Future IRP cycles will include a projection for wind acquisition with and without geothermal until a clearer picture emerges regarding geothermal dry hole risk.
- The Company will continue to refine the wind integration modeling approach; establish a technical review committee (TRC) and a schedule and project plan for the next wind integration study. The TRC will be formed and members identified within 30 days of the effective date of the IRP Order. Within 30 days of the effective date of the IRP Order, a schedule for the study will be established, including full opportunity for stakeholder involvement and progress reviews by the TRC that will allow the final study to be submitted with the next IRP.
- The Company identified over 100 MW of geothermal resources as part of a least-cost resource portfolio. Continue to refine resource potential estimates and update resource costs in 2011-2012 for further economic evaluation of resource opportunities.
- Continue to explicitly include geothermal projects as eligible resources in future all-source RFPs.
- Evaluate procurement of Oregon solar photovoltaic resources in 2012 via the Company’s solar RFP.
- Acquire additional Oregon solar resource through RFPs or other means in order to meet the Company’s 8.7 MW compliance obligation
- Work with Utah parties to investigate solar program design and deployment issues and opportunities in late 2011 and 2012, using the Company’s own analysis of Wasatch Front roof top solar potential and experience with the Oregon solar pilot program. As recommended in the Company’s response to comments under Docket No. 07-035-T14, the Company requested that the Utah Commission establish “a process in the fall of 2011 to determine whether a continued or expanded solar program in Utah is appropriate and how that program might be structured.” (Rocky Mountain Power, “Re: Docket No. 07-035-T14 – Three year assessment of the Solar Incentive Program”, December 15, 2010).
- Investigate, and pursue if cost-effective from an implementation standpoint, commercial/residential solar water heating programs.

- Pursue opportunities for acquiring biomass CHP resources, primarily through the PURPA Qualifying Facility contracting process.
- Proceed with an energy storage demonstration project, subject to Utah Commission approval of the Company's proposal to defer and recover expenditures through the DSM surcharge.
- Initiate a consultant study in 2011 on incremental capacity value and ancillary service benefits of energy storage.
- Conduct a study of grid flexibility for accommodating variable energy resources (VER) as part of the next IRP filing.
- Develop and refine strategies for renewable portfolio standard compliance in California and Washington.
- PacifiCorp will expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. The Company will be selective in its discussion to avoid conflict between the IRP, RPS Implementation Plan and RPS Compliance Report.

Status

The Company acquired 160 MW of renewable resources between 2010 and 2012. With the decrease in natural gas prices, lower power prices, lack of load and changes in the expectation for the extension of the federal tax incentives, incremental wind in the current preferred portfolio first appears in 2024 and is driven by renewable portfolio requirements. The renewable portfolio standard requirements will be met by purchasing renewable energy credits in the market consistent with the preferred portfolio and Action Item 1b in the 2013 IRP Action Plan.

Using historical wind generation data from wind resources in the PacifiCorp system, the Company completed a study evaluating how much wind capacity has historically been available during peak load conditions. This analysis has been used to update the Company's capacity contribution assumptions for wind resources as summarized in Volume II, Appendix O of the 2013 IRP.

Case C-16 in the 2013 IRP is one of five core cases in the "Targeted Resources" theme (Cases C-15 through C-18) which evaluates meeting renewable portfolio standards using available geothermal resources, modeled as a power purchase agreement, before using other RPS-eligible renewable technologies. These cases are characterized by alternative assumptions for specific resource types to understand how those assumptions influence resource portfolios, costs and stochastic risk.

For its 2012 Wind Integration Study, PacifiCorp established a technical review committee (TRC). The TRC members were selected based on their experience and background in the field of the wind integration study and regulatory requirements. PacifiCorp held several meetings with the TRC to review the detailed calculations of reserve requirements to integrate wind resources in its balancing authority areas. The six TRC members' biographies and the wind integration study's schedule are posted on PacifiCorp's IRP website. The TRC will provide their report of the wind study in early May 2013 and the Company will file the report within 30 days of the receiving it.

A Geothermal Information Request report (public version) was posted to the IRP website and IRP participants were notified on June 28, 2012. Geothermal resources were explicitly included in the All Source request for proposal (RFP) for 2016 resources, which was subsequently terminated. In addition, geothermal power purchases approximated based on information received from the 2016 All Source RFP were included as proxy resources in the supply side table in Volume I, Chapter 6 of the 2013 IRP.

As a result of the 2010S request for proposals, the Company acquired the Black Cap Solar Facility which is located on 20 acres a few miles west of Lakeview, Oregon. Ideally situated on the sunny side of the Cascade Range, the two-megawatt facility is equipped with a sophisticated tracking system that optimizes the sun's power. Lakeview is in Oregon's High Desert and sits at an elevation of 4,800 feet. The valley opens to the south and enjoys more than 300 days of sunshine a year. Black Cap started generating electricity for customers in October 2012 and will produce approximately 4,500 megawatt-hours of electricity each year – comparable to the energy needed to serve 400 average homes annually. The Company will apply the experience gained through the project in its next request for proposals.

A request for proposals will be issued in the second quarter of 2013 to acquire further Oregon solar resources as identified in the 2103 IRP Action Item 1d.

On October 1, 2012, the Utah Public Service Commission approved a large expansion of the Utah Solar Incentive Program in Docket 11-03-104. The program will incentivize the installation of 60 MW of distributed solar generation in systems sized one MW and below over the next five years. The program began accepting applications on January 15, 2013.

The final Cadmus memo provided to the public on October 31, 2012 provides updated supply curves for commercial/residential solar water heating programs which were used in the 2013 IRP.

The Company continues to pursue resources through PURPA Qualifying Facility contracting process. The 2013 IRP Action item 2b will assess the opportunities and provide a market analysis for acquiring biomass CHP resources in the 2013 IRP Update.

The energy storage demonstration project progressed to the point of testing the five kilowatt-hour electrostatic generator at moderated speed in a partially integrated prototype. At this speed the actual resonances encountered closely matched theoretical models. By the end of 2012 the prototype was being transported to a higher speed spin pit to test the output voltages produced in generation mode. The energy storage demonstration development and demonstrated report was sent to the public in May 2012. Due to lack of supplier funding, in 2013 this project is no longer being pursued by PacifiCorp.

A consultant study was initiated in 2011 on incremental capacity value and ancillary service benefits of energy storage. HDR Engineering (HDR) was retained by PacifiCorp to perform an Energy Storage Study to evaluate a portfolio of energy storage options. The scope of the study was to develop a current catalog of commercially available and emerging large, utility-scale and distribution scale energy storage technologies as well as define respective applications, performance characteristics and estimated capital and operating costs for each technology. The

results are documented in the December 2011 report that was sent to the public on September 4, 2012. The report can be found at the following website:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/Report_Energy-Storage-Screening-Study2012.pdf

A study was completed for a needs assessment of PacifiCorp's flexible resources to meet its reserve requirements, which is in Volume II, Appendix F.

In this IRP, the development and refinement for RPS compliance in California and Washington and the RPS compliance strategies and the role of REC sales and purchases are outlined in Volume I, Chapters 3, 7, and 8. This action item has been superseded by Action Item 1b in Table 9.1.

Action Item 2: Intermediate/ Base-load Thermal Supply-side Resources 2014-2016

- Acquire a combined-cycle combustion turbine (CCCT) resource at the Lake Side site in Utah by the summer of 2014; the plant is proposed to be constructed by CH2M Hill E&C, Inc. ("CH2M Hill") under the terms of an engineering, procurement, and construction (EPC) contract. This resource corresponds to the 2014 CCCT proxy resource included in the 2011 IRP preferred portfolio.
- PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update. The reexamination will include documentation of capital cost and operating cost tradeoffs between resource types.
- Consider siting additional gas-fired resources in locations other than Utah. Investigate resource availability issues including water availability, permitting, transmission constraints, access to natural gas, and potential impacts of elevation.
- Issue an all-source RFP in early 2012 for potential acquisition of peaking/intermediate/baseload resources by the summer of 2016 to fill any remaining resource need indicated by an updated load and resource balance reflecting the results of DSM request for proposals, acquisition of front office transactions, reserve margin sensitivity analysis, and other relevant information.

Status
Lake Side 2 project remains on schedule and is within budgeted costs to meet an online date of June 2014. The All Source RFP was issued in January 2012 for a 2016 resources. However, the RFP was later terminated. The need for post-2014 gas resource(s) is delayed until 2024 based on a needs assessment study that PacifiCorp completed as part of the justification in the termination of the All Source RFP in September 2012. The timing of this resource is consistent with the 2013 IRP preferred portfolio. A cost comparison of different gas resources was thus unnecessary due to lack of resource need.

Action Item 3: Firm Market Purchases 2011-2020

- Acquire economic front office transactions or power purchase agreements as needed through summer 2016. Resources will be procured through multiple means, such as periodic mini-RFPs that seek resources less than five years in term, and bilateral negotiations.
- Closely monitor the near-term and long-term need for front office transactions and adjust planned acquisitions as appropriate based on market conditions, resource costs, and load expectations. Actively search for market options that could cost-effectively defer acquisition or construction of a 2016 CCCT resource.

Status
A market RFP was issued in March 2012 which resulted in the acquisition of 125 MW for 2013, 100 MW for 2014, 100 MW for 2015 and 100 MW for 2016 on the east side of the system. Due to the change in the load forecast and reduced resource needs from the needs assessment in the All Source RFP process, no additional front office transactions or power purchases were acquired through the summer of 2016. This action item has been superseded by Action Item 3a in Table 9.1.

Action Item 4: Plant Efficiency Improvements 2011-2020

- Continue to pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company's future CO_2 and other environmental compliance requirements.
- Successfully complete the dense-pack coal plant turbine upgrade projects scheduled for 2011 and 2012, totaling 33 MW, subject to economics. The 2012 10-year plan includes 13.8 MW capacity increase in 2013.
- Seek to meet the Company's updated aggregate coal plant net heat rate improvement goal of 478 British thermal unit per kilowatt-hour (Btu/kWh) by 2019. (PacifiCorp Energy Heat Rate Improvement Plan, April 2010).
- Continue to monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.
- For the next IRP complete a study of cost-effective and reliable production efficiency opportunities at generating facilities (station load reduction opportunities not currently being captured in the IRP) where the Company has sole ownership of the facility. The resource opportunities identified will be modeled against competing demand and supply-side resources in the next IRP. Those selected will be targeted for completion by 2015 provided plant outages are not required.

Status
An ongoing effort to identify promising new potential plant/unit improvement opportunities has been completed through the normal course of business. The effort includes the identification and reporting of heat rate improvement opportunities and future project plans. Along with monitoring turbine and other equipment technologies as above, this item will now also be tracking the aggregate coal plant net heat rate improvement goals. This action item will continue annually.

The identified projects will be documented within the annual Heat Rate Improvement Plan, or HRIP, and will be posted on the IRP website. The HRIP report includes a 10 year forecast of major projects intended to modify the unit design heat rate of the Company's coal fired plants. This action item has been superseded by Action Item 6a in Table 9.1.

Action Item 5: Class 1 DSM 2011-2020

- Acquire at least 140 MW of incremental cost-effective DSM resource by 2013 and up to 250 MW by 2015.
- Finalize an agreement for the commercial curtailment product (which includes customer-owned standby generation opportunities). If cost effective, the company will file for approval by the 3rd quarter of 2012.
- Complete an analysis of the economic feasibility of Class 1 irrigation load control in the west by the second quarter of 2012. If the analysis suggests Class 1 irrigation load control is economic in the west, the Company will source delivery of a program through a request for proposals concurrent with the re-sourcing of Class 1 irrigation load control program delivery in the east by the third quarter of 2012.
- Issue a request for proposal in 2012 to re-procure the delivery of the Cool Keeper program following the 2013 control season. For the request for proposal, the Company will seek market approaches acceptable to Utah regulators to expand the program beyond its current level beginning in 2014.

Status
There were no incremental Class 1 DSM resources added in 2011 or 2012 as a result of the Company's revised load forecast and deferral of need for a 2016 resource. The Company canceled the commercial curtailment product due to the revised/lowered load forecast that also contributed to the cancelation of the All Source Request for Proposals.

The Company completed an analysis of the feasibility and costs of west-side Class 1 irrigation control and collected costs through a 2012 request for proposal. Despite finding the resource reasonably viable, it was not selected as an economic resource in the first ten years of the 2013 IRP preferred portfolio (see action item 7b).

An RFP was issued in January 2013 to re-procure the delivery of Utah's Cool Keeper air conditioner load management program. Provisions in the RFP will allow for program expansion as conditions warrant.

Action Item 6: Class 2 DSM 2011-2020

- Apply the 2011 IRP conservation analysis as the basis for the Company's next Washington I-937 conservation target setting submittal to the Washington Utilities and Transportation Commission for the 2012-2013 biennium. The Company may refine the conservation analysis and update the conservation forecast and biennial target as appropriate prior to submittal based on final avoided cost decrement analysis and other new information.

- Acquire at least 900 MW and up to 1,800 MW of cost-effective Class 2 programs by 2020, equivalent to at least 4,533 GWh and up to 9,066 GWh. Acquire at least 520 MW and up to 1000 MW of cost-effective Class 2 DSM by 2016.
  - Adjusted to reflect 2011 IRP's initial MW contribution from Class 2 resources expected to be acquired in Oregon (reduces the MW contribution from Oregon from 562 MWs by 2020 to 283 MWs, a 279 MW reduction)
- By 1st quarter of 2012 file a residential home residential home comparison report program in Utah and Washington, and investigate broader applications by the end of 2014 that can be implemented by 2016.
- By 3rd quarter 2012 the Company will submit for commission approval a plan to acquire energy efficiency resources from the Company's Special Contract customers in Utah and Idaho that can be reliably verified and delivered by 2016, and will pursue those resources provided the Commissions in those states approve a cost-recovery mechanism for the plan.
- By 1st quarter 2012 issue a system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs targeting savings from the residential and small commercial sectors that can be delivered beginning in 2013. The Company will seek to acquire all cost-effective resources that are available from the request for proposal. The cost effectiveness analysis will consider any adverse impact on the existing DSM programs. The results of the RFP will be known prior to the Company seeking acknowledgement of the final short list for the all-source RFP. The Company will promptly file for commission approvals to implement the cost-effective programs.
- For the next IRP, prior to beginning modeling and screening of DSM, and as part of the public input process, provide an analysis of alternatives to the current supply curve bundling and ramping methods for modeling energy efficiency measures. By the end of 2012 provide an analysis of the sufficiency of current staffing levels to achieve programmatic cost effective energy efficiency targets established in this plan.
- Leverage the distribution energy efficiency analysis of 19 distribution feeders in Washington (conducted for PacifiCorp by Commonwealth Associates, Inc.) for analysis of potential distribution energy efficiency in other areas of PacifiCorp's system provided the Company receives approval by the appropriate Commission for recovery of the study cost through the demand-side customer efficiency surcharge. (The Washington distribution energy efficiency study final report was completed December 26, 2011.) -- Include in the 2013 IRP a detailed plan and schedule to implement cost-effective Conservation Voltage Reduction (CVR) in each state as approved by the state.
- By the end of 2013 perform a high-level screening of the remaining 60 percent of its distribution circuits in each of the states to identify circuits where cost-effective energy savings appear viable and detailed circuit study is warranted provided the Company receives approval by the appropriate state commission for recovery of the study cost through the demand-side customer efficiency surcharge.
- In the 2013 IRP include the results of the CVR evaluation to date.

Status

The Company filed its Washington Initiative 937 10 year conservative forecast and 2012-2013 biennial targets with the Washington Utilities and Transportation Commission on January 31. 2012.

The Company exceeded its 2011 and 2012 Class 2 DSM acquisition goals by 242,438 megawatt-hours (MWh) (29 percent), achieving 1,087,747 MWh against the goal amount of 845,036 MWh. The Company proposed offering residential home comparison report programs in Utah and Washington in April, 2012, and after regulatory discussions implemented the report program in August, 2012.

In addition, the Company is actively working with the Energy Trust of Oregon on a pilot program to be offered to PacifiCorp customers in 2013 and 2014. The acquisition of energy efficiency resources from special contract customers was discussed with the Utah DSM Advisory Steering Group in 2013. The steering group recommended the issue be a subject of the next contract negotiations with the special contract customers.

The Company issued a system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs targeting savings from residential and small commercial sectors in March, 2012. Full processing of the RFP proposals was put on "hold" following the Company's revised load forecast and cancellation of 2012 All Source RFP pending the results of the 2013 IRP. The Company intends to complete the processing of the proposal's received for implementation in fourth quarter of 2013.

As part of the modeling and screening of the DSM the Company has disaggregated and narrowed price bundles. Documentation on ramping and supply curve methods was provided to stakeholders. A review of staffing levels to achieve programmatic cost effective energy efficiency targets in the 2013 IRP has been completed. Volume II, Appendix D (Demand-Side Management and Supplemental Resources) provides the Energy Efficiency ramp rates, the DSM potential study and other demand side management studies.

Prior to the end of 2012 no approval had been provided by the major states to conduct detailed analysis for CVR. The high level screening has been completed. The 2013 IRP details for the implantation of CVR projects in Washington have been provided based on the results of Tier 1 and 2 studies. This action item has been superseded by Action Item 7a in Table 9.1.

Action Item 7: Class 3 DSM 2011-2020

- During 2012 update the Conservation Potential Assessment to more accurately reflect Class 1 and 3 DSM resource opportunities in regards to 1) market and regulatory capabilities and climates in each state, 2) interactions within and between Class 1 and Class 3 resource potentials identified, and 3) the impact of existing Class 3 programs on product potential.
- During 2012 have a third-party consultant review and prepare a report on how other utilities treat price-responsive products in their resource planning process (for example, as an adjustment to their load forecast and/or as a firm planning resource), and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively.
- For the 2013 IRP provide a sensitivity analysis, similar to portfolio development Case 31 in the 2011 IRP, that more accurately reflects incremental Class 3 product opportunities

(incremental to Class 1 products, other Class 3 products, and to existing impacts of Class 3 products the Company is already running).

- Implement in Utah and Washington (subject to regulatory approvals) residential information pilots to test the effects of providing customers greater amounts of usage information on the quantity of electricity they consume. The pilots will leverage the existing Automatic Meter Reading (AMR) metering currently available in these states. Pilots will consist of three test groups each receiving varying levels of usage information:

    - Group 1 – Home comparison reports and energy conservation suggestions.
    - Group 2 – Daily usage data through Home Energy Monitoring software (key component to pricing products)
    - Group 3 – Home comparison reports, energy savings suggestions, and daily usage data through Home Energy Monitoring software

  Pilots will be implemented in 2012, run throughout 2013, and an analysis and recommendations prepared in 2014, prior to the development of the 2015 IRP.

- If the analysis of Class 1 irrigation load control in the west (see action item 5) indicates that such programs are non-economic, investigate, through a pilot program in Oregon a Class 3 irrigation time-of-use program as an alternative approach for managing irrigation loads in the west.

Status

The 2012 Conservation Potential Assessment work was expanded to provide a greater assessment of opportunities, interactions and impacts of Class 1 and 3 program potentials, including the impacts of the Company's existing Class 3 products. The report also undertook an assessment of how other utilities treat demand response resources in their integrated resource planning processes. This assessment was distributed to stakeholders in September 2012. The 2012 Conservation Potential Assessment is included in Appendix D. A memo summarizing Cadmus findings regarding treatment of price responsive projects by 23 other utilities in their IRPs was distributed to PacifiCorp IRP public stakeholders in September. Cadmus key findings included the following:

1) Like PacifiCorp, most utilities surveyed (13 of the 23) account for existing time-of use (TOU) program impacts directly in their load forecast. Only PacifiCorp and two Missouri utilities directly complete incremental price-responsive programs opportunities with other resources options in IRP models.
2) Five of the 23 utilities surveyed did not account for incremental TOU programs in their IRPs at all, due to no expected program growth or limited participation programs that are too small to warrant load adjustments.
3) Only PacifiCorp and two other utilities delineate program impacts from event driven pricing programs (e.g., critical peak pricing and demand bidding).

Sensitivity case S-10 in the 2013 IRP provides an analysis that reflects incremental Class 3 products (incremental to Class 1, other Class 3 products, and to existing impacts of Class 3 products the Company is already running).

The implementation of residential information pilots in conjunction with the Home Energy Report programs in Utah and Washington were deemed to be too small to return statistically relevant results and expanding group size was determined cost prohibitive for the value of the information to be obtained. Based on other utility experiences with Home Energy Report programs (and their supporting program evaluations), its believed information on varying levels of information on customer behavior and savings can be obtained through running variations of the existing Group 1 program (standard Home Energy Report program) and from learning's from the impact the evaluations of other utility programs running such variations.

Because the Oregon Class 1 irrigation load control in the west was not selected as economic in the first ten years of the 2013 IRP preferred portfolio, the Company will investigate through an Oregon Class 3 irrigation time of use pilot program as an alternative for managing irrigation loads in the west – See Action Item 7b in Table 9.1.

Action Item 8: Planning Process Improvements Process Improvement

- Incorporate plug-in electric vehicles and Smart Grid technologies as a discussion topic for the next IRP.

Status
A presentation and question and answer session on PacifiCorp's Smart Grid evaluation and implementation efforts was given to the IRP public stakeholder meeting in December 2012. This action item has been superseded by Action Item 11a in Table 9.1.

Action Item 9: Coal Resource Actions

- The Company will host a technical workshop for stakeholders and the [Oregon] commissioners on February 17, 2012, respectively, for stakeholders that have a confidentiality agreement in place. At the technical workshop, the Company will review with stakeholders the methodology, assumptions and recently completed analysis of upcoming Naughton Unit 3 emission control investments. The Naughton Unit 3 analysis will be provided to stakeholders, subject to confidentiality agreements, as soon as practicable. At the technical workshop, the Company will present the methodology, assumptions and results of a Coal Replacement Study screening analysis performed for Jim Bridger 3, Jim Bridger 4, and Hunter 1 at a minimum. The Company will complete the analysis on as many other units as possible within the time constraints. The Company will also present information pertaining to planned investments in the Craig and Hayden facilities of which the Company has ownership share but does not have operational responsibilities. The screening analysis will be performed using a spreadsheet model that assumes a gas-fired CCCT, scaled to the size of the coal unit being analyzed, replaces the coal unit in 2015. The screening analysis will include line-item results showing annual capital costs and fixed and variable operating costs for each coal unit and the replacement CCCT resource. The screening analysis will be performed on three different market scenarios pairing varying levels of natural gas prices and CO_2 costs. At least one scenario will include a low gas/high CO_2 pairing. The screening analysis will report a rank order of the nominal levelized net PVRR benefit/cost on a per kW-month basis for each scenario. The Company will make available to stakeholders that have signed appropriate confidentiality agreements the assumptions and results of the screening Study five business days before the technical workshop.

- The Company will include in its 2011 IRP update an updated Coal Replacement Study focusing on those units analyzed in the screening analysis as described above. The updated Coal Replacement Study will be performed using the System Optimizer model and will explore a range of natural gas prices and CO_2 costs in varying combinations. The updated Coal Replacement Study will discuss and evaluate flexibility in the emerging environmental regulations and the associated economics that may present options to the Company to avoid early compliance costs by offering to shut down certain individual units prior to the end of their currently approved depreciable lives. In the updated Study, the Company will provide a concise explanation and transparent example of its treatment of post-2030 costs and will provide an analysis that shows the results of treatments of environmental investments made prior to 2015 both avoidable and unavoidable.

Status

A confidential workshop was held with stakeholders and a commission workshop was held in February 2012 in Salem. Confidential material was distributed in February 2012 to stakeholders that are signatories under the appropriate protective order. The Screening analysis was completed for all units (Naughton Unit 3 was excluded pending completion of updated Naughton Unit 3 Certificate of Public Convenience and Necessity analysis) and the results were reviewed in a February 2012 workshop. Gas-fired CCCT characteristics were reported in the screening model. Four market scenarios were modeled:

- Base gas/base CO_2 price
- Low gas/no CO_2 price
- Base gas/high CO_2 price
- Low gas/high CO_2 price

The information was provided as part of a “Summary Results” worksheet in the screening model. Screening model results were provided to stakeholders in February 2012. Confidential and redacted versions of the Coal Replacement Study were included with the 2011 IRP Update report submitted to the state commissions on March 30, 2012. The Company has analyzed in the 2013 IRP environmental investments required to meet known and prospective compliance obligations across PacifiCorp’s existing coal fleet. Supported by analyses performed as part of the 2013 IRP and analyses performed in recent regulatory filings, the Company plans to convert Naughton Unit 3 to a natural gas-fired facility and to install environmental investments required to meet near term compliance obligations at the Hunter Unit 1, Jim Bridger Unit 3, and Jim Bridger Unit 4 generating units. Installation of emission control equipment at these facilities will reduce emissions of nitrous oxides (NO_X) and sulfur dioxide (SO_2) and contribute to improved visibility in the region. The Company plans to continue to evaluate environmental investments required to meet known and prospective environmental compliance obligations at existing coal units in future IRPs and future IRP Updates.

Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process in the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations tied to Regional Haze rules, Mercury and Air Toxics Standards (MATS), regulation of coal combustion residuals (CCR), and regulation of cooling water intakes are considered in the development of *all* resource portfolios developed for the 2013 IRP. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. In addition to integrating coal unit environmental investment decisions into the portfolio development process, the Company has completed detailed financial analysis of near-term investment decisions in Confidential Volume III of the 2013 IRP. This action item has been superseded by Action Item 8a through 8d in Table 9.1.

Action Item 10: Transmission

- In the scenario definition phase of the IRP process, the Company will address with stakeholders the inclusion of any transmission projects on a case-by-case basis.
- Develop an evaluation process and criteria for evaluating transmission additions and review with stakeholders which transmission projects should be included and why.
- Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgement (including Wallula to McNary and Sigurd to Red Butte).

Status
As part of the 2013 IRP the Company has incorporated five separate Energy Gateway scenarios which were run for each of the core cases. The Company has developed an evaluation tool, System Operational and Reliability Benefits Tool (SBT), to evaluate transmission additions. The SBT identifies, measures, and monetizes benefits that are incremental to those identified in the resource portfolio modeling process. Analysis using the SBT supports investment in the Sigurd to Red Butte transmission project and preliminary application of the SBT to the Windstar to Populus transmission project supports continued permitting of Energy Gateway Segment D. The Company has reviewed the tool with stakeholders throughout the 2013 IRP process. In contrast to the 2011 IRP, where analysis of Energy Gateway transmission investments preceded resource portfolio modeling, Energy Gateway transmission investments have been integrated into the portfolio modeling process for the 2013 IRP. This was achieved by replicating the development of resource portfolios among five different Energy Gateway transmission scenarios. Consequently, 94 unique core case resource portfolios were produced in the 2013 IRP, nearly five times the number of core case portfolios developed for the 2011 IRP.

The SBT will continue to be developed and will be applied to additional Energy Gateway transmission projects for analysis in future IRPs. This action item has been superseded by Action Item 9a through 9c in Table 9.1.

Action Item 11: Planning Reserve Margin

- For the 2011 IRP Update include the results of a System Optimizer portfolio sensitivity analysis comparing the resource and cost impacts of a 12 percent versus 13 percent planning reserve margin.

Status

The 2011 IRP Update included a summary of a planning reserve margin analysis that presented the impact on resource need when the planning reserve margin is assumed to change from 13 percent to 12 percent. Appendix I in the 2013 IRP, which was provided and discussed with stakeholders, was completed by Ventyx and provides the resource and cost impact of a 12 percent vs. 13 percent planning reserve margin. This action item has been superseded by Action Item 10a in Table 9.1.

Acquisition Path Analysis

Resource Strategies

PacifiCorp worked with stakeholders to define 19 input scenarios, or "core cases", which were applied across five different Energy Gateway transmission scenarios totaling 94 different variations of resource portfolios.[81] The 19 different core cases were categorized into four different themes. The array of core case definitions, grouped by theme, provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by shifts in policies and changes to fundamental market conditions. The four core case themes are summarized as follows:

(9) **<u>Reference</u>:** There are three different core cases developed for the Reference Theme. Each case relied upon base case assumptions for market prices, environmental policy inputs, energy efficiency assumptions, and load projections. RPS assumptions differentiate the three cases in the Reference Theme, with one case assuming no state or federal RPS requirements, one case assuming only state RPS requirements, and one case assuming both state and federal RPS requirements must be met.

(10) **<u>Environmental Policy</u>:** There are 11 different core cases developed for the Environmental Policy Theme. Five of the 11 cases reflect base case assumptions for Regional Haze requirements on existing coal units, and six of the 11 cases assume more stringent Regional Haze requirements. Differentiating the sets of cases with different Regional Haze compliance requirements are varying assumptions for market prices (low, medium, and high), CO_2 prices (zero, medium, and high), RPS requirements (with and without state and federal RPS), and energy efficiency.

(11) **<u>Targeted Resources</u>:** There are four different core cases developed for the Targeted Resource Theme. Each of the cases is characterized by alternative assumptions for specific resource types to understand how these assumptions influence resource portfolios, costs, and risk. One of the four cases prevents CCCT resources to be added to the resource portfolio and assumes energy efficiency resources can be acquired at an accelerated rate. The second of the four cases in this theme assumes that geothermal power purchase agreement resources will be used to meet RPS requirements. The third of four cases in this theme assumes a spike in

[81] One of the input scenarios is applicable to four out of the five Energy Gateway transmission scenarios.

power prices over the period 2017 through 2022 and assumes natural gas prices will rise above base case levels over the entirety of the planning horizon. The fourth case in this theme targets clean energy resources and assumes CO_2 prices rise consistent with a federal hard cap scenario, that natural gas prices rise above those assumed in the base case, that federal tax incentives for renewable resources are extended through 2019, and that energy efficiency resources can be acquired at an accelerated rate.

(12) **Transmission:** The Transmission Theme included one core case, which assumes that third party transmission can be purchased from a newly built line as an alternative to

Given current load expectations, portfolio modeling performed for the 2013 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when FOTs and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2013 IRP shows that new renewable resource needs are driven by RPS compliance obligations, and all else equal, this result is not significantly changed if federal tax incentives are assumed to be extended. Beyond load, the most significant driver affecting resource selection in the 2013 IRP are market price and policy assumptions that trigger early coal unit retirements as an alternative to environmental investments required to meet known and emerging environmental regulations. For these reasons, the acquisition path analysis focuses on load trigger events, and combinations of environmental policy and market price trigger events that would require alternative resource acquisition strategies. For each trigger event, Table 9.2 lists the associated planning scenario and both short-term (2013-2022) and long-term (2023-2032) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[82] PacifiCorp's decision mechanism is centered on the business planning and IRP processes, which together constitute the decision framework for making resource investment decisions. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. In developing the IRP action plan and path analysis, the Company considers common elements across multiple resource strategies (for example, base levels of each resource type across many least-cost portfolios optimized according to different futures), planning contingencies and resource flexibility, and continuous evaluation of market/regulatory developments and resource options.

PacifiCorp uses the IRP and business plan to serve as decision support tools for senior management to determine the most prudent resource acquisition paths for maintaining system

[82] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

reliability and low-cost electricity supplies, and to help address strategic positioning issues. The key strategic issues as outlined in this IRP include (1) addressing regulatory risks in the areas of climate change and renewable resource policies; (2) accounting for price risk and uncertainty in making resource acquisition decisions; (3) load uncertainty; and (4) determining the appropriate level and timing of long-term transmission expansion investments, accounting for the regulatory risks and uncertainties outlined above.

Table 9.2 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2013-2022)	Long Term Resource Acquisition Strategy (2023-2032)
Higher sustained load growth	High economic drivers and increased demand from industrial customers	• Increase acquisition of FOTs • Increase acquisition of Class 1 DSM direct load control resources in the 2017 – 2020 timeframe • Accelerate acquisition of a gas-fired thermal resource to 2019 • Increase acquisition of RECs to maintain compliance with RPS requirements consistent with load growth expectations by state	• Accelerate acquisition of thermal resources to 2023 • Increase acquisition of Class 1 DSM direct load control resources. • Balance timing of thermal resource acquisition and Class 1 DSM resources with FOTs and cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective RPS compliance strategies, including tradeoffs between resource acquisition and use of compliance flexibility mechanisms like banking and use of unbundled RECs
Lower sustained load growth	Low economic drivers suppress load requirements	• Reduce acquisition of FOTs • Continue to purse Class 2 DSM energy efficiency resources	• Reduce acquisition of gas-fired thermal resources • Pursue peaking gas-fired resources to meet load growth • Balance timing of thermal resource acquisition and Class 1 DSM resources with FOTs and cost-effective Class 2 DSM energy efficiency resources
Softening of the natural gas market combined with greenhouse gas policies that increase the cost of coal unit operation	Excess gas supply with increasing well productivity and/or technological innovation and dampened demand from limited use in the transportation sector and no liquefied natural gas exports. Legislative action to implement new greenhouse gas polices or new regulations implemented with equivalent costs expected to approach $75/ton by 2032.	• Increase acquisition of FOTs and/or Class 2 DSM energy efficiency resources • Pursue strategic low cost gas conversion of existing coal units • Retire high cost coal units and accelerate acquisition of replacement natural gas-fired thermal resources • Accelerate acquisition of gas-fired thermal resources to 2019 to meet load growth expectations	• Pursue strategic low cost gas conversion of existing coal units • Retire high cost coal units and accelerate acquisition of replacement natural gas-fired thermal resources • Accelerate acquisition of cost-effective renewable resources • Balance timing of thermal resource acquisition and Class 1 DSM resources with FOTs and cost-effective Class 2 DSM energy efficiency resources

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2013-2022)	Long Term Resource Acquisition Strategy (2023-2032)
Strengthening of the natural gas market combined with greenhouse gas policies that increase the cost of coal unit operation	High oil prices support liquefied natural gas exports with lagging global shale development and demand for natural gas in the transportation sector increases beyond 2020. Legislative action to implement new greenhouse gas polices or new regulations implemented with equivalent costs in excess of $130/ton by 2032.	• Increase acquisition of FOTs • Accelerate acquisition of incremental Class 2 DSM energy efficiency resources • Accelerate and increase acquisition of renewable resources	• Pursue strategic low cost gas conversion of existing coal units • Retire high cost coal units and pursue acquisition of low emission replacement thermal resources such as nuclear and generating technologies with carbon capture and sequestration • Accelerate and increase acquisition of renewable resources. • Build additional transmission infrastructure to gain access to cost effective renewable resource opportunities.

Procurement Delays

The main procurement risk is an inability to procure resources in the required time frame to meet the need. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2013 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or a material change in the market for fuels, materials, electricity, or environmental or other electric utility regulations, may change the Company's entire resource procurement strategy.

Possible paths PacifiCorp could take if there was either a delay in the online date of a resource or, if it was no longer feasible or desirable to acquire a given resource, include the following:

- Consider alternative bids if they haven't been released under a current RFP.
- Issue an emergency RFP for a specific resource.
- Move up the delivery date of a potential resource by negotiating with the supplier/developer.
- Rely on near-term purchased power and transmission until a longer-term alternative is identified, acquired through PacifiCorp's mini-RFPs or sole source procurement.
- Install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the 13 percent planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Resource differences between PacifiCorp's 2013 IRP and the 2011 IRP Update relates primarily to a decreased load forecast and lower natural gas and power prices. These drivers result in a significant reduction of resources which include removal of natural gas, wind, FOT, DSM, and distributed generation resources. As compared to the 2011 IRP Update, the 2013 IRP preferred portfolio includes increased distributed solar due to the expanded Utah Solar Incentive Program. Table 9.3 compares the 2013 IRP preferred portfolio with the 2011 IRP Update portfolio for the 10 years covered by both portfolios (2013-2022), indicating year by year capacity differences by major resource categories (yellow highlighted table). The major resource changes since the 2011 IRP Update include the removal of two CCCT resources (CCCT F 2x1 and CCCT G 1x1) included in the portfolio by 2016 and 2019 respectively, reduction in DSM influenced by an updated resource potential study and additional detail in representing DSM in the current IRP modeling framework, increased distributed solar resources, and removal of wind resources. As discussed in Chapter 8 and identified in Table 9.1, renewable energy credits will be used to meet state RPS requirements.

Table 9.3 – Portfolio Comparison, 2013 Preferred Portfolio versus 2011 IRP Update Portfolio

2013 IRP vs 2011 IRP Update

2013 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2013-2022**
Coal Plant Turbine Upgrades		14	-	-	-	-	-	-	-	-	-	**14**
Gas		-	645	-	-	-	-	-	-	-	-	**645**
Wind		-	-	-	-	-	-	-	-	-	-	-
Other Renewables / Solar		12	14	17	16	18	14	14	14	15	15	**149**
DSM, Class 1		-	-	-	-	-	-	-	-	-	-	-
DSM, Class 2		115	117	103	101	97	92	90	81	80	82	**956**
Distributed Generation		1	1	1	1	1	1	1	1	1	1	**11**
Total Long Term Resources		**141**	**777**	**121**	**119**	**116**	**106**	**104**	**95**	**96**	**98**	**1,774**
Utah Capacity Purchase *		200	-	-	-	-	-	-	-	-	-	**200**
East - Firm Market Purchases		-	-	-	-	-	37	151	248	19	161	62
West - Firm Market Purchases		650	709	845	983	1,102	1,172	1,172	1,172	1,172	1,172	1,015
Firm Market Purchases		**850**	**709**	**845**	**983**	**1,102**	**1,209**	**1,323**	**1,420**	**1,191**	**1,333**	**1,277**

Study includes Naughton 3 gas conversion in 2015
FOT in resource total are 10-year averages

2013 IRP Preferred Portfolio less 2011 IRP Update (2012 Business Plan)

	Capacity (MW)											Resource Totals
Resource	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2013-2022**
Coal Plant Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Gas		-	8	-	(597)	-	-	(393)	-	-	-	**(982)**
Wind		-	-	-	-	-	-	(225)	(225)	-	(75)	**(525)**
Other Renewables / Solar		7	11	14	16	18	14	14	14	15	15	**138**
DSM, Class 1		(57)	(20)	(97)	-	-	-	-	-	-	-	**(174)**
DSM, Class 2		4	(2)	(19)	(23)	(29)	(28)	(32)	(44)	(45)	(52)	**(269)**
Distributed Generation		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	**(41)**
Total Long Term Resources		**(50)**	**(6)**	**(106)**	**(607)**	**(16)**	**(19)**	**(640)**	**(260)**	**(34)**	**(116)**	**(1,853)**
Utah Capacity Purchase *		-	-	-	-	-	-	-	-	-	-	-
East - Firm Market Purchases		(150)	(300)	(331)	(300)	(300)	(263)	(145)	(52)	(35)	23	(185)
West - Firm Market Purchases		(188)	(52)	(47)	416	506	437	639	377	458	446	299
Firm Market Purchases		**(338)**	**(352)**	**(378)**	**116**	**206**	**174**	**494**	**325**	**423**	**469**	**114**

FOT in resource total are 10-year averages

2011 IRP Update (2012 Business Plan - Dec. 2011)

	Capacity (MW)											Resource Totals
Resource	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2013-2022**
Coal Plant Turbine Upgrades	19	14	-	-	-	-	-	-	-	-	-	**14**
Gas	-	-	637	-	597	-	-	393	-	-	-	**1,627**
Wind	-	-	-	-	-	-	-	225	225	-	75	**525**
Other Renewables / Solar	4	4	3	3	-	-	-	-	-	-	-	**10**
DSM, Class 1	70	57	20	97	-	-	-	-	-	-	-	**174**
DSM, Class 2	114	110	118	122	124	126	120	122	125	125	134	**1,225**
Distributed Generation	5	5	5	5	5	5	5	5	5	5	5	**52**
Total Long Term Resources	**213**	**191**	**783**	**227**	**726**	**131**	**125**	**745**	**355**	**130**	**214**	**3,627**
Utah Capacity Purchase *	200	200	-	-	-	-	-	-	-	-	-	20
East - Firm Market Purchases	17	150	300	331	300	300	300	296	300	54	138	247
West - Firm Market Purchases	927	838	761	892	567	596	735	533	795	714	726	716
Firm Market Purchases	**1,145**	**1,188**	**1,061**	**1,223**	**867**	**896**	**1,035**	**829**	**1,095**	**768**	**864**	**983**

FOT in resource total are 10-year averages

Table 9.4 provides a comparison between the 2013 Business Plan and the 2013 IRP Preferred Portfolio. The drivers of the differences between the 2013 IRP Preferred Portfolio and the 2013 Business Plan include, reduced loads, removal of wind resources consistent with use of renewable energy credit purchase for RPS compliance, decreased DSM and FOTs due to decrease in load, and increase in distributed solar due to the Utah Solar Incentive Program.

Table 9.4 – Portfolio Comparison, 2013 Business Plan versus 2013 Preferred Portfolio

2013 IRP vs 2013 Business Plan

2013 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2013-2022**
Coal Plant Turbine Upgrades		14	-	-	-	-	-	-	-	-	-	**14**
Gas		-	645	-	-	-	-	-	-	-	-	**645**
Wind		-	-	-	-	-	-	-	-	-	-	-
Other Renewables / Solar		12	14	17	16	18	14	14	14	15	15	**149**
DSM, Class 1		-	-	-	-	-	-	-	-	-	-	-
DSM, Class 2		115	117	103	101	97	92	90	81	80	82	**956**
Distributed Generation		1	1	1	1	1	1	1	1	1	1	**11**
Total Long Term Resources		**141**	**777**	**121**	**119**	**116**	**106**	**104**	**95**	**96**	**98**	**1,774**
Utah Capacity Purchase *		200	-	-	-	-	-	-	-	-	-	20
East - Firm Market Purchases		-	-	-	-	-	37	151	248	19	161	62
West - Firm Market Purchases		650	709	845	983	1,102	1,172	1,172	1,172	1,172	1,172	1,015
Firm Market Purchases		**850**	**709**	**845**	**983**	**1,102**	**1,209**	**1,323**	**1,420**	**1,191**	**1,333**	**1,097**

Study includes Naughton 3 gas conversion in 2015
FOT in resource total are 10-year averages

2013 IRP Preferred Portfolio less 2013 Business Plan

	Capacity (MW)											Resource Totals
Resource	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2013-2022**
Coal Plant Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Gas		-	7	-	-	-	-	-	-	-	-	**7**
Wind		-	-	-	-	-	(100)	(100)	(100)	(100)	-	**(400)**
Other Renewables / Solar		7	11	14	16	18	14	14	14	15	15	**138**
DSM, Class 1		-	-	-	-	-	-	(1)	(100)	-	-	**(101)**
DSM, Class 2		29	26	8	9	7	(4)	(7)	(19)	(25)	(29)	**(4)**
Distributed Generation		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	**(41)**
Total Long Term Resources		**32**	**40**	**18**	**21**	**21**	**(94)**	**(98)**	**(209)**	**(113)**	**(17)**	**(401)**
Utah Capacity Purchase *		-	-	-	(200)	(200)	(200)	(200)	(200)	-	-	(100)
East - Firm Market Purchases		-	(92)	(51)	(88)	(72)	(93)	(95)	(52)	(62)	18	(59)
West - Firm Market Purchases		(268)	(166)	(233)	(46)	(66)	(45)	(45)	(45)	(45)	(45)	(100)
Firm Market Purchases		**(268)**	**(258)**	**(283)**	**(335)**	**(338)**	**(337)**	**(339)**	**(297)**	**(106)**	**(27)**	**(259)**

FOT in resource total are 10-year averages

2013 Business Plan (December 2012)

	Capacity (MW)											Resource Totals
Resource	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2013-2022**
Coal Plant Turbine Upgrades	19	14	-	-	-	-	-	-	-	-	-	**14**
Gas	-	-	638	-	-	-	-	-	-	-	-	**638**
Wind	-	-	-	-	-	-	100	100	100	100	-	**400**
Other Renewables / Solar	4	4	3	3	-	-	-	-	-	-	-	**10**
DSM, Class 1	-	-	-	-	-	-	-	1	100	-	-	**101**
DSM, Class 2	101	86	90	95	93	90	95	97	100	104	110	**960**
Distributed Generation	5	5	5	5	5	5	5	5	5	5	5	**52**
Total Long Term Resources	**130**	**109**	**736**	**104**	**98**	**95**	**201**	**202**	**305**	**210**	**115**	**2,174**
Utah Capacity Purchase *	200	200	-	-	200	200	200	200	200	-	-	120
East - Firm Market Purchases	62	-	92	51	88	72	130	246	300	81	143	120
West - Firm Market Purchases	1,055	918	875	1,078	1,029	1,168	1,217	1,217	1,217	1,217	1,217	1,115
Firm Market Purchases	**1,317**	**1,118**	**967**	**1,128**	**1,318**	**1,440**	**1,546**	**1,662**	**1,717**	**1,297**	**1,360**	**1,355**

Study includes Naughton 3 gas conversion in 2015
FOT in resource total are 10-year averages

Resource Procurement Strategy

To acquire resources outlined in the 2013 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, the Company will use its IRP models to support resource evaluation as part of the procurement process, with updated assumptions including load forecasts, commodity prices, and regulatory requirement information available at the time that the resource evaluations occur. This will ensure that the resource evaluations account for a long-term system benefit view in alignment with the IRP portfolio analysis framework as directed by state procurement regulations, and with business planning goals in mind.

The sections below profile the general procurement approaches for the key resource categories covered in the action plan: renewable energy credits, DSM, thermal plants, distributed generation, and market purchases.

Renewable Energy Credits

The Company uses a shelf RFP as the primary mechanism under which the Company will issue subsequent RFPs to meet most of the renewable energy credit acquisition goals over the IRP action plan and business planning horizons.

Demand-side Management

PacifiCorp uses a variety of business processes to implement DSM programs. The outsourcing model is preferred where the supplier takes the performance risk for achieving DSM results. In other cases, PacifiCorp manages the program and contracts out specific tasks. A third method is to operate the program completely in-house. The business process used for any given program is based on operational expertise, performance risk and cost-effectiveness.

To support the DSM procurement program, the IRP models are used for resource valuation purposes to gauge the cost-effectiveness of programs identified for procurement shortlists. For Class 2 DSM programs, PacifiCorp performs a "no cost" load shape decrement analysis to derive program values using its stochastic production cost model, *Planning and Risk*, similar to what was done for the 2011 IRP. The load shape decrement analysis is included in Volume II< Appendix N.

Distributed Generation

Distributed generation, both solar and biomass, were found to be cost-effective resources in the context of IRP portfolio modeling. PacifiCorp's procurement process will continue to provide an avenue for such new or existing resources to participate. These resources will be advantaged by being given a minimum bid amount (MW) eligibility that is appropriate for such an alternative, but that is also consistent with PacifiCorp's then-current and applicable tariff filings (qualifying facility (QF) tariffs for example).

PacifiCorp will continue to participate with regulators and advocates in legislative and other regulatory activities that help provide tax or other incentives to renewable and distributed generation resources. The Company will also continue to improve representation of distributed generation resource in the IRP models.

Assessment of Owning Assets versus Purchasing Power

As the Company acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, the Company would be in a better position to control costs, make life extension improvements, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, the Company can hedge itself from the uncertainty of relying on purchasing power from others.

Depending on contract terms, purchasing power from a third party in a long term contract may help mitigate and may avoid any liabilities associated with closure of a plant. Short-term purchased power contracts could allow the Company to defer a long term resource acquisition. A long-term purchase power contract relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect the Company's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels would prompt the Company to continue to look for measures to lower CO_2 emissions of existing thermal plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures that would be cost-effective and practical from operational and regulatory perspectives. As noted earlier in the IRP, known and prospective environmental regulations can impact coal plant utilization and investment decisions.

Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. To lower the emission levels for existing thermal plants, options include economic early retirement, changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and adoption of new technologies such as CO_2 capture with sequestration when commercially proven. Indirectly, plant carbon risk can be addressed by acquiring offsets in the form of renewable generation and energy efficiency programs. Under an aggressive CO_2 regulatory environment, and depending on fuel costs, coal plant idling and replacement strategies may become tenable options.

High CO_2 costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, as is currently being pursued for the Naughton Unit 3 generating unit. A major issue is whether new technologies will be available that can be exchanged for existing coal economically, particularly if market and policy drivers lead to large scale and abrupt early retirements across the region and the U.S. as a whole.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the Company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years the Company has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. The Company's risk management policy and hedging program exists to achieve the following goals: (1) to ensure that reliable power is available to serve customers; (2) to reduce net power cost volatility; and (3) to protect customers from significant risk. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. The Company does not speculatively trade commodities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. The Company cannot predict the direction or sustainability of changes in forward prices. Therefore, the Company hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the Company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed at least annually by the Company's risk oversight committee. The risk oversight committee includes the Company's chief financial officer, treasurer, director of risk management, assistant general counsel, controller, and senior vice president of commercial and trading. The risk oversight committee makes recommendations to the president of PacifiCorp Energy, who ultimately must approve any change to the risk management policy. The Company's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of the Company's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) limits. These limits force the Company to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, the Company either purchases or sells power in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, the Company's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. The Company's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. The Company incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the Company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and the Company's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of the Company's hedging activities is documented in the Company's Risk Management Policy. In May 2010, the Company moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that the Company has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times the Company buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, the Company steadily and adaptively meets its hedge goals through the use of this technique while staying within VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which the Company's program automatically responds), has been a significant decrease in the Company's longer-dated hedge activity, *i.e.,* four years forward on a rolling basis.

As a result of the hedging collaboratives, the Company made the following material changes to its policy in May 2012: (l) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward l2-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. The Company also agreed to provide a new confidential semi-annual hedging report.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the Company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. The Company then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, the Company optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, the Company commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. The Company also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, the Company does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, the Company reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

Portfolio

The Company has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. The Company may have short or long positions in power depending on the shortfall or excess of the Company's total economic generation relative to customer load requirements at a given point in time.

The Company hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. The Company's 2011 IRP analysis shows that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.,* a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. The Company's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by Company traders.

The Company's hedge program does not rely on a long power position. However, the Company's hedge program takes into account the Company's full portfolio and utilizes continuously updated correlations of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that the Company would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

The Company's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in the Company's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the Company's confidential semi-annual hedging report which it began providing as a result of the hedging collaborative.

Instruments

The Company's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. The Company chooses instruments that generally have greater liquidity and lower transaction costs. The Company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the Company's fixed price exposure.

External Review

In the Company's 2009 Utah General Rate Case, the Division of Public Utilities requested that Blue Ridge, a consulting firm knowledgeable with commodity hedging, review the Company's hedging program. The Blue Ridge Report affirmatively concluded that the Company's risk management policy and hedging program was well-documented, controlled and adhered to generally accepted industry standards as follows:

> *Overall, Blue Ridge found that the Company's commercial trading and risk management programs (and the related hedging programs) are well-documented and controlled and adhere to generally accepted standards found elsewhere in the industry. The Company has well-stated goals and strategy that is aimed at mitigating price volatility. In addition,*

> *our review of the Company's internal documents showed that the Company is self-monitoring compliance with accepted commercial trading and risk management procedures through its own internal audit function.*[83]
>
> *The question has been asked, "Why hedge?" The answer lies in one fundamental statement: prices and supplies for energy commodities (crude oil, natural gas, electricity, etc.) can and have been extremely volatile. The benefit of hedging is that when prices are rising (either rapidly in the short term or gradually in the long term), a hedged portfolio of supply should mitigate the effect of those increases. However, the opposite is also true. When prices fall suddenly, a hedged portion of the supply can cost the utility and its customers the difference between the prices that were available at the current time versus the hedged prices for that supply. This cost (when netted against any gains) along with the administrative costs associated to operate and manage the trading operations is considered the insurance premium associated with a hedged portfolio.*
>
> *[H]aving a "no hedge" policy clearly exposes consumers to significant (and likely) price swings. Assuming that an upward price trend continues (despite recent price levels and short-term price forecasts), consumers are very likely to pay higher prices for energy absent some level of hedging and price volatility mitigation.*[84]

The National Regulatory Research Institute (NRRI) provided guidance related to natural gas hedging by utilities. The Utah Division of Public Utilities sponsored a presentation by NRRI to the Utah Commission in June 2009. The NRRI Report[85] indicates that, for many years, state commissions have suggested that failure to engage in hedging (*i.e.*, buying natural gas in the day-ahead market or spot price) may be imprudent. The NRRI Report provides guidance on standards for determining the prudence of a utility's hedging cost. The NRRI Report states, "Second-guessing and micromanaging should be avoided." It explains, "Second-guessing is contrary to the traditional prudence standard, and in addition, creates distorted incentives for utility hedging." Instead, it recommends that, "[a]ccording to the prudence standard, a commission should maintain authority to evaluate the reasonableness of (1) a hedging strategy ex ante, and (2) the execution of the strategy." The NRRI Report suggests that a Commission could set an *ex ante* standard by, for example, defining an acceptable level of risk tolerance to price volatility. The Company agrees with the NRRI Report's recommended approach to Commissions' reviews of the prudence of the Company's risk management policy and hedging program and welcomes direction from the Commissions on the Company's risk management policy and hedging program on a going forward basis.

Dr. Frank Graves of The Brattle Group, retained by the Company to assess its risk management policy and hedging program, summarized his general findings and conclusions as follows:

---

[83] Independent Third-Party Evaluation of Net Power Cost Evaluation Rocky Mountain Power 2009 General Rate Case, Prepared for Utah Division of Public Utilities, Prepared by Blue Ridge Consulting Services, Inc, Docket No. 09-035-23 (Utah PSC October 7, 2009) at 2.

[84] *Id.* at p 2 and 26.

[85] Gas Hedging Presentation to The Public Service Commission of Utah Technical Conference, Ken Costello, The National Regulatory Research Institute, Docket No. 09-035-21 (Utah PSC June 3, 2009), available at: http://www.psc.utah.gov/utilities/electric/09docs/0903521/TechConf%206-3-09/Gas%20Hedging.ppt%20 (UT%20PSC).pdf

First, risk management is about controlling the potential width (and shape) of the distribution of future costs and not about minimizing costs. Even though it is possible to trim or avoid extreme prices with hedging, that trimming cannot reduce expected costs, because the risk protections come at a fair price. What you gain from hedging as avoided "downside" (bad) outcomes, you must lose as avoided "upside" (good) outcomes as well, and vice versa for your hedging counterparty. The two, corresponding positions must balance for no expected net gain. Thus, the minimization of energy costs has nothing to do with good risk management practices.

Second, the Company's hedging policies and practices, i.e. its analytic methods, risk metrics and controls, and hedging instruments, are fully in line with good industry practices. Like most electric utilities, the Company relies primarily on swaps purchased in regular installments over time. This avoids attempts to second-guess or "time" the market, while also assuring that hedges are steadily accrued, subject to risk-based guidelines for the needed quantity of total hedges. Consistent adherence to these methods, along with evidence of careful monitoring and control of the resulting risk metrics (keeping them within appropriate bounds), are the relevant standards for prudence review of the EBA costs the Company has incurred.

Third, U.S. natural gas markets in the late 2007 through 2011 period (when PacifiCorp entered the hedges) were dominated by the unexpectedly rapid and inexpensive development of shale gas, compounded by the credit crisis and deep recession. During the first two years of this period there were few indications that shale gas would become a major component of U.S. gas supply. Only towards the end of the period did it become evident that shale gas would become a prominent and quite inexpensive part of the natural gas supply in the U.S. Even natural gas exploration and production firms aggressively leading the development of the hydraulic fracturing technology that caused this price drop have been badly surprised by the rapid price reductions.[86] Therefore, the outlook for natural gas supply and prices were very different throughout the period during which the hedges were entered than it is today. It is imperative that the merits of a hedging program be evaluated based on the market conditions and information availability as of the time of the transaction.

Fourth, it would not have been useful or normal for the Company to have liquidated any of its prior hedges in the middle of this price decline. It might appear so in hindsight, but the spot prices we ultimately observed are not similar to the way risks or expected costs appeared at any time in the hedge procurement period. Utility companies should not and do not generally liquidate hedges if/when the forward price curve shifts and causes prior hedges to become "out of the money" (i.e. to have a higher cost than replacement hedges). Because hedge positions are liquidated at prevailing prices, early liquidation cannot be expected to benefit the Company or its customers; the expected alternative cost (whether re-hedged or not) would have been the then prevailing forward prices – with no net savings likely. (As it turns out, liquidation and not re-hedging, i.e. dramatically

[86] For example, an August 2009 article in the New York Times cites senior management at exploration and production companies that the continual drop puts the viability of smaller companies at risk. See Clifford Krauss, "Natural Gas Price Plummet to a Seven-Year Low," New York Times, August 21, 2009.

> *increasing the Company's risk exposure, would have been cheaper. But this can only be known in hindsight, and pursuing this strategy would have been very speculative, possibly in violation of company risk-control guidelines and prior regulatory agreements about hedging activity.*
>
> *Fifth, natural gas and power hedges should be considered together, which is what the Company does. The literature and common practice in hedging is solidly on the side of taking advantage of positions that predictably tend to offset each other, in order to reduce the cost and scope of hedging transactions that are needed. Electric and gas operations fit this model very nicely, in that they naturally tend to be correlated. Separating them for review would create perverse and untenable incentives for both regulation and operations.*

Dr. Graves also described the purpose and overarching goal of risk management and hedging as follows:

> *A hedge is a trade designed to reduce risk, where risk is understood to mean the potential width (and shape) of the distribution of <u>future</u> costs (or revenues). Risk management is NOT about improving (reducing) the mean of this distribution of future costs (nor about increasing expected revenues). Risk also should not be confused with after-the-fact regret about whether a hedge proved to be necessary or attractive relative to remaining unhedged. In fact, risk and regret are mostly conflicting or competing goals, in that the more you lock down future prices (reduce ex ante risk) the greater the chance of eventually departing materially from the ex post cost of going unhedged. Conversely, if you wanted to have no regret about realized spot prices being lower than your hedges, than you should not hedge in the first place – but this would be risky! Some of the debate in regulatory review about risk management prudence involves confusion between these two concepts. However, the appropriate reference point is not the realized outcomes, which can only be known in hindsight (and which will only be better or worse than the hedges by luck), but the market information and outlook available at the time the hedges and risk reduction targets were committed.*

Commission Review

Six out of six commissions that regulate PacifiCorp have approved net power costs for at least some portion of the 2012 calendar year period without any hedging disallowances. The Oregon Commission in the 2011 Transition Adjustment Mechanism, Docket No. UE 227, in the face of significant hindsight challenges from certain parties, found all of the Company's hedge transactions to be prudent and praised the Company's risk management policy and hedge program. Specifically, the Oregon Commission stated in the order:

> *The company's Risk Management Policy includes sound hedging goals, methodologies, and targets. Its policies and procedures were well articulated, and its specific hedging targets were made clear in advance to the company and its traders. Moreover, the company's hedging program appears to be robustly designed and well documented. The company provided ample contemporaneous documentation of the policies and procedures in effect at the time the hedges were executed, including its method of identifying, measuring, and managing risk, its hedging targets, its credit policies and*

procedures, and its approved portfolio structures, as well as detailed procedures governing company enforcement of these policies. [87]

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to CO_2 emissions, renewable resources to meet compliance requirement, change in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of CO_2 emission and renewable standard compliance rules.

To address these risks, the Company evaluates resources in the IRP and for competitive procurements using a range of CO_2 prices consistent with the scenario analysis methodology adopted for the Company's IRP portfolio evaluation process. The Company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the

[87] Order No. 11 435, Docket UE-227 (Ore. PUC [November 4, 2011]) at page 11.

need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with the Company's resource investments determined to be prudent by state commissions is a risk borne by customers.

2013

Integrated Resource Plan

Volume II - Appendices

Let's turn the answers on.

April 30, 2013

PACIFICORP

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

This 2013 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Wind Turbine: *Leaning Juniper I Wind Project*
Thermal-Gas: *Chehalis Power Plant*
Solar: *Black Cap Photovoltaic Solar Project*

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APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2013 Integrated Resource Plan ("IRP"), including scenario development for case sensitivities. The load forecast used in the IRP is an estimate of the energy sales, and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand in order to develop timely response of resources.

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

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

Summary Load Forecast

The Company updated its load forecast in July 2012. Relative to the load forecast prepared for the 2011 IRP update, PacifiCorp system sales decreased approximately 0.8 percent in average annual growth through 2022. The lower load forecast is driven by reduced industrial sector loads in Utah and Wyoming that reflect load request cancellations and postponements prompted by prolonged recessionary impacts and permitting issues. The most current load forecast also incorporates projections of increased industrial self-generation driven largely by lower wholesale gas prices. Finally, the Company's new industrial load forecast uses regression analysis in place of probability assessment of customer-provided forecasts.

Tables A.1 and A.2 show the annual load and coincident peak load forecast excluding load reduction projections from new energy efficiency measures (Class 2 DSM).[1] Tables A.3 and A.4 show the forecast changes relative to the 2011 IRP update load forecast for loads and coincident system peak, respectively.

[1] Class 2 DSM load reductions are included as resources in the System Optimizer model.

Table A.1 – Forecasted Annual Load Growth, 2013 through 2022 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2013	61,556,386	14,877,800	4,453,504	903,816	25,153,750	10,190,043	3,740,820	2,236,653
2014	62,698,447	15,150,179	4,479,048	905,134	25,718,951	10,408,489	3,779,427	2,257,219
2015	63,527,998	15,371,114	4,510,405	908,752	26,010,382	10,626,524	3,819,927	2,280,894
2016	63,431,505	15,638,182	4,561,495	916,004	26,478,252	10,856,135	3,868,348	1,113,089
2017	63,246,311	15,821,900	4,587,861	918,237	27,010,019	11,012,432	3,895,861	
2018	64,219,328	16,003,367	4,630,207	923,755	27,542,259	11,188,259	3,931,482	
2019	65,183,187	16,181,469	4,672,594	928,941	28,073,752	11,360,999	3,965,432	
2020	66,226,672	16,377,833	4,722,544	935,083	28,622,538	11,563,805	4,004,870	
2021	66,917,769	16,491,188	4,746,086	935,580	29,021,169	11,698,580	4,025,165	
2022	67,814,244	16,652,789	4,784,841	938,914	29,514,597	11,866,488	4,056,614	
Average Annual Growth Rate for 2013-2022								
2013-2022	1.08%	1.26%	0.80%	0.42%	1.79%	1.71%	0.90%	

Table A.2 – Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2013	10,135	2,329	743	143	4,632	1,277	685	327
2014	10,331	2,377	752	140	4,745	1,302	684	331
2015	10,494	2,408	758	141	4,826	1,326	701	334
2016	10,359	2,457	765	143	4,930	1,349	714	
2017	10,513	2,492	772	144	5,014	1,371	721	
2018	10,687	2,522	803	145	5,100	1,390	727	
2019	10,815	2,547	786	146	5,194	1,410	732	
2020	10,972	2,576	795	144	5,290	1,429	737	
2021	11,133	2,604	801	145	5,387	1,448	748	
2022	11,280	2,631	807	146	5,475	1,467	754	
Average Annual Growth Rate for 2013-2022								
2013-2022	1.20%	1.36%	0.92%	0.23%	1.88%	1.56%	1.07%	

Table A.3 – Annual Load Growth Change: November 2011 Forecast less July 2012 Forecast (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2013	(1,734,236)	(462)	(71,339)	(41,408)	(1,456,454)	(76,649)	(53,890)	(34,034)
2014	(2,500,990)	(65,008)	(83,667)	(44,776)	(1,828,067)	(261,914)	(173,476)	(44,082)
2015	(3,234,992)	(54,370)	(86,451)	(45,926)	(2,173,032)	(572,064)	(249,858)	(53,291)
2016	(3,933,522)	(12,540)	(93,075)	(47,494)	(2,616,993)	(803,790)	(327,267)	(32,363)
2017	(5,299,846)	(100,262)	(96,937)	(65,836)	(3,032,564)	(1,615,158)	(389,090)	
2018	(5,513,237)	(96,772)	(99,309)	(65,757)	(3,148,301)	(1,690,539)	(412,558)	
2019	(5,740,510)	(93,880)	(100,878)	(66,020)	(3,248,967)	(1,807,650)	(423,115)	
2020	(6,015,091)	(99,673)	(102,183)	(67,092)	(3,423,365)	(1,888,205)	(434,572)	
2021	(6,284,160)	(94,696)	(103,330)	(68,142)	(3,583,213)	(1,991,980)	(442,800)	
2022	(6,682,754)	(218,649)	(151,116)	(71,341)	(3,739,231)	(2,051,017)	(451,401)	

Table A.4 – Annual Coincident Peak Growth Change: November 2011 Forecast less July 2012 Forecast (Megawatts)

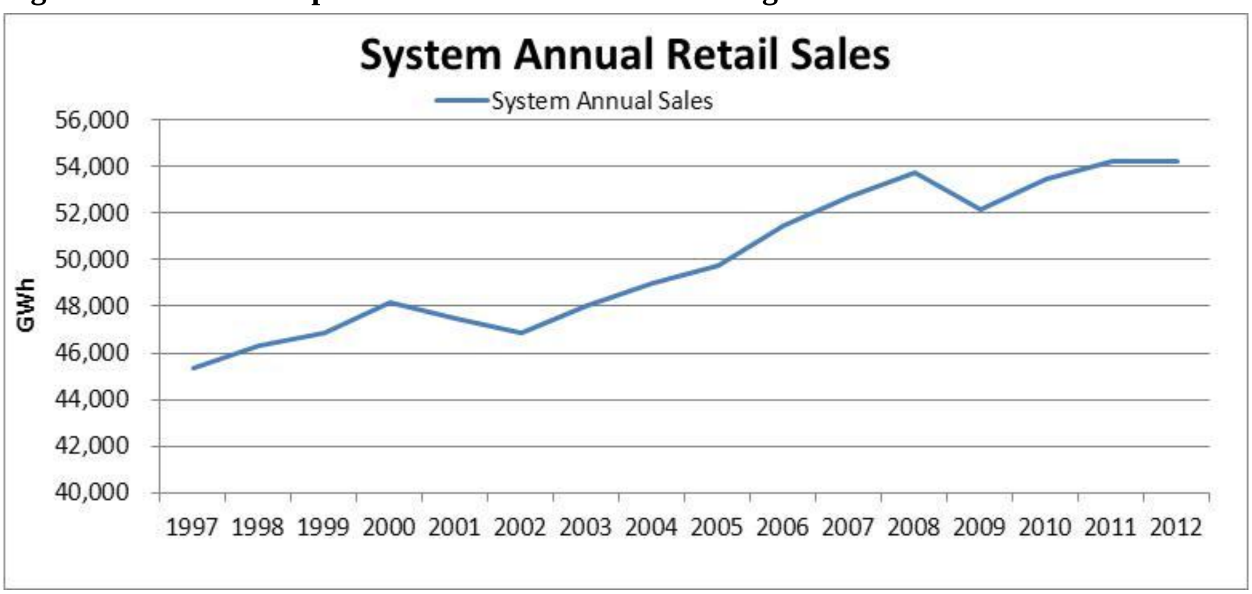
Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2013	(283)	(19)	(17)	(16)	(169)	(28)	(15)	(18)
2014	(403)	(29)	(18)	(16)	(240)	(46)	(34)	(20)
2015	(491)	(25)	(24)	(18)	(295)	(63)	(49)	(17)
2016	(521)	(5)	(24)	(19)	(321)	(90)	(63)	
2017	(687)	(17)	(24)	(24)	(375)	(173)	(73)	
2018	(707)	(14)	(4)	(24)	(408)	(180)	(77)	
2019	(763)	(16)	(25)	(24)	(429)	(190)	(79)	
2020	(804)	(18)	(25)	(24)	(463)	(196)	(79)	
2021	(843)	(15)	(26)	(25)	(485)	(209)	(83)	
2022	(887)	(38)	(25)	(20)	(497)	(222)	(84)	

Load Forecast Assumptions

Regional Economy by Jurisdiction

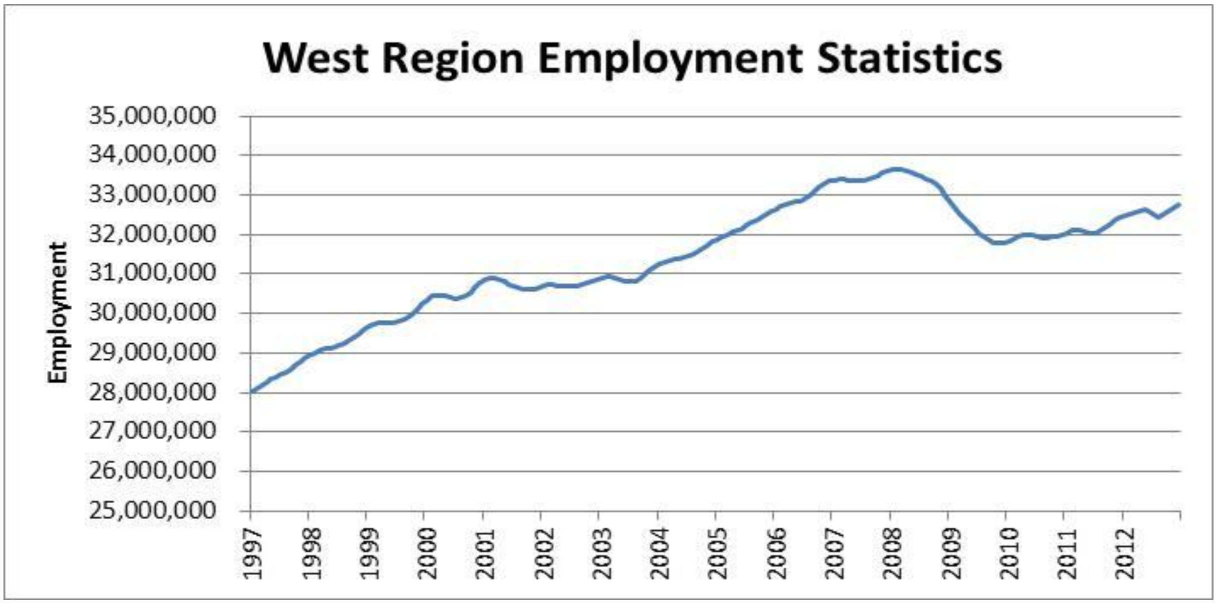
The PacifiCorp electric service territory is comprised of six states and within those states the Company serves a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics for each area. The Company uses both economic data, such as employment, and population information, such as household data, to forecast its retail sales. Looking at historical sales data for PacifiCorp, 1997 through 2012, in Figure A.1 and Western Regional historical employment data in Figure A.2, it is apparent that the Company's retail sales are correlated to economic conditions in its service territory, and most recently the 2008-2009 recession.[2]

Figure A.1 – PacifiCorp Annual Retail Sales 1997 through 2012



[2] The historical sales data provide in Figure A.1 is annual weather normalized retail sales for the PacifiCorp system.

Figure A.2 – West Region Employment Statistics 1997 through 2012



Source: United States Department of Labor, Bureau of Labor Statistics

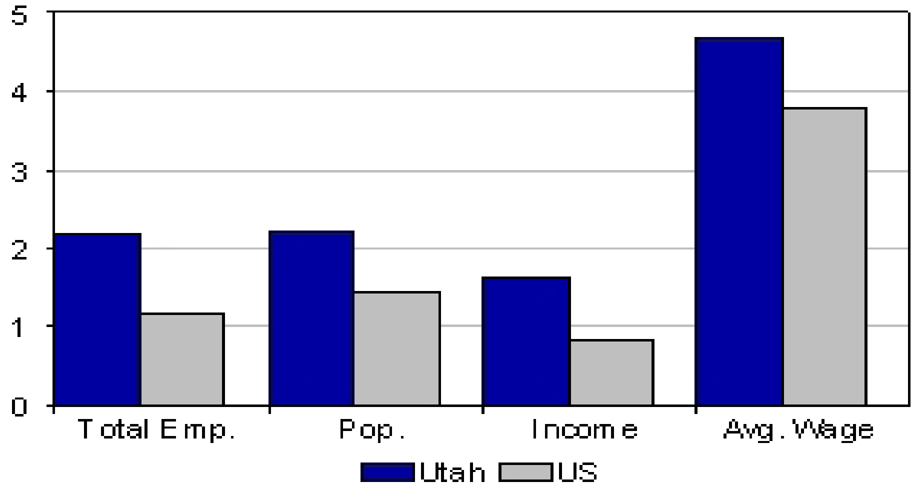
Given the correlation between employment and electricity usage, it is important to understand the changes in the employment and household formation forecasts that contributed to the decrease in the 2013 IRP load forecast. The majority of economic and household formation forecasts provided by IHS Global Insight in its February 2012 forecast were lower than the February 2011 forecast. The primary reason for the decrease across all states is underperformance relative to the prior forecast, and the economy not recovering in a manner that was as anticipated, or at a more protracted rate of growth. The effect of the decrease in the forecasts provided by IHS Global Insight is that it lowers the expected retail sales forecast. Following is a discussion by state of IHS Global Insights expectations and change in their forecast relative to the 2011 IRP Update.

Utah

The Utah economy continues to benefit from a relatively young, well educated, and well-qualified workforce to attract employers, and ranks highly in quality-of-life measures, which contributes to population growth. Utah is expected to remain among the leading states in terms of job growth over the next five years, with payrolls increasing an average of 2.2 percent annually. Figure A.3 below shows the growth in Utah relative to the United States average.[3]

[3] Source: IHS Globe Insight, April 2012

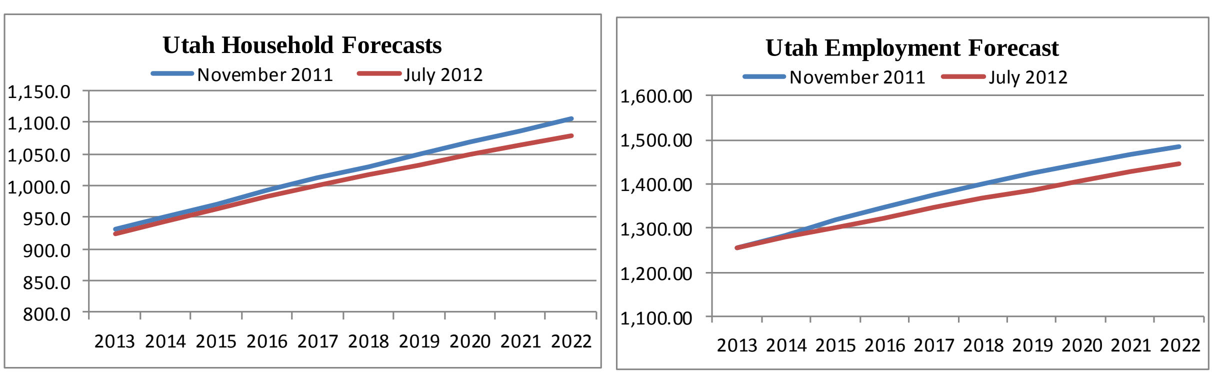
Figure A.3 – Growth Relative to the US Average (Average annual percent change, 2011 to 2013)



PacifiCorp serves 26 of the 29 counties in the state of Utah. The Company expects retail sales to continue to grow in the state, with increases in the construction sector from a housing recovery and continued strong growth in the extraction industries. A risk to the load forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment which translates to potential swings in the retail sales forecast.

To gain an understanding of one of the drivers of the changes in the Company retail sales forecast for Utah, Figure A.4, below, shows the change in household and employment forecasts for the 2011 IRP Update relative to the 2013 IRP load forecast. IHS Global Insight lowered its forecast of household formation and employment for Utah relative to the November 2011 load forecast citing slowed job gains at the end of 2011 and beginning of 2012.

Figure A.4 – IHS Global Insight Utah Household and Employment forecasts from the November 2011 load forecast and the July 2012 load forecast

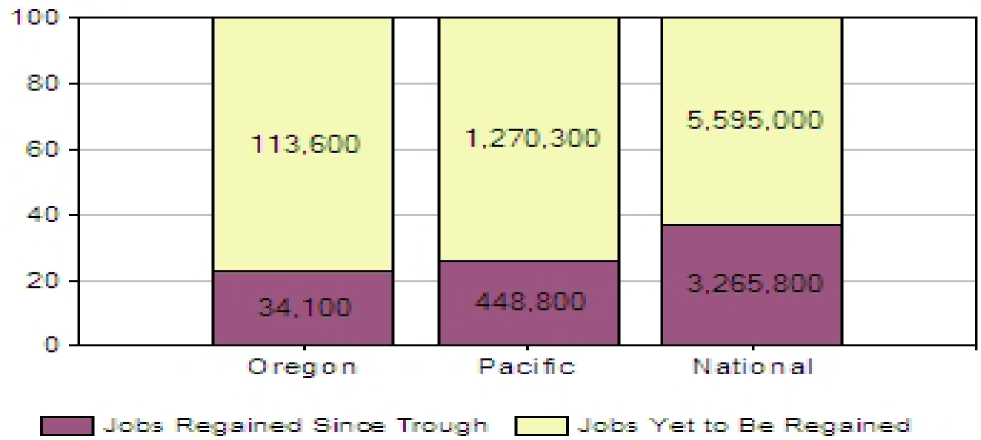


Oregon

The Oregon economy has faced a slow recovery from the 2008-2009 recession. Most of the employment gains in 2010 were tepid and not enough to pull Oregon out of the deep hole the recession had dug. The construction sector has been performing well relative to the country, due to commercial construction projects, however, it is still dependent on the rebound of the residential market. PacifiCorp serves 25 of the 36 counties in Oregon, but only 28 percent of ultimate electric retail sales in the state of Oregon.[4] Medford Oregon is the largest metropolitan area served by PacifiCorp in Oregon and has seen tepid growth, less than 0.4 percent, since the 5.8 percent decline in gross domestic product ("GDP") in 2009.[5]

Figure A.5 is an illustration of Oregon's economic recovery relative to the Pacific and National regions.

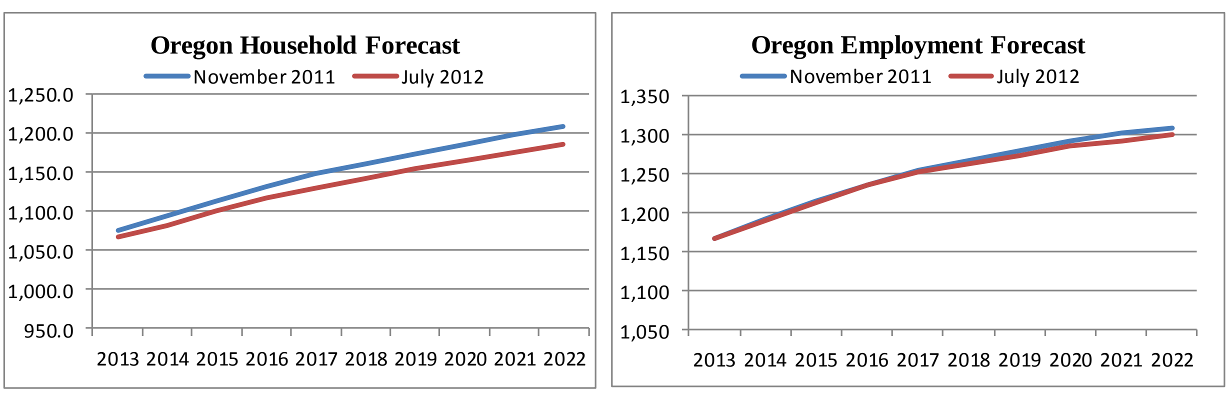
Figure A.5 – Recession Recovery: Changes in Employment (Percent)



Source: Globe Insight, April 2012

IHS Global Insight provides county level economic data to reflect the PacifiCorp service territory in Oregon. A comparison of the IHS Global Insight forecast for the Company's Oregon service territory showing a decrease in household formation and employment from the 2013 IRP load forecast relative to the 2011 IRP update provided in Figure A.6 below.

Figure A.6 – IHS Global Insight Oregon service territory Household and Employment forecasts from the November 2011 load forecast and the July 2012 load forecast

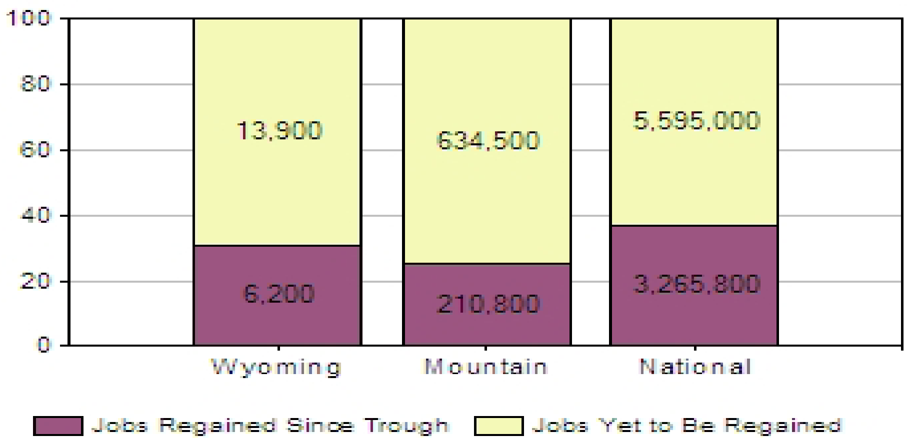


[4] Source: Oregon Public Utility Commission, 2011 Oregon Utility Statistics.
[5] Source: Bureau of Economic Analysis.

Wyoming

Economic activity in Wyoming is expected to moderate significantly over the medium term. Between 2012 and 2013, employment will expand just 1.0 percent annually on average. The state's employment growth was generally faster than the U.S. average since the recovery began, however, the mining and extraction sector, which has been the main driver of growth in recent years, will contract over the medium term despite a recent uptick in mining activity to serve global growth. IHS Global Insight's expects that federal permitting issues, land use policies, and environmental concerns will restrain new exploration in the state.[6] Figure A.7 is an illustration of Wyoming's economic recovery relative to the Mountain and National regions.

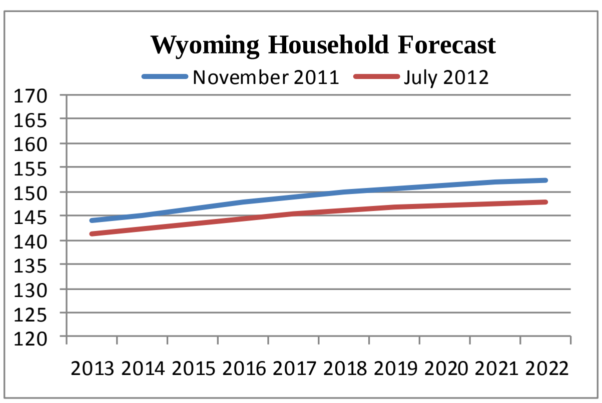
Figure A.7 – Recession Recovery: Changes in Employment (Percent)

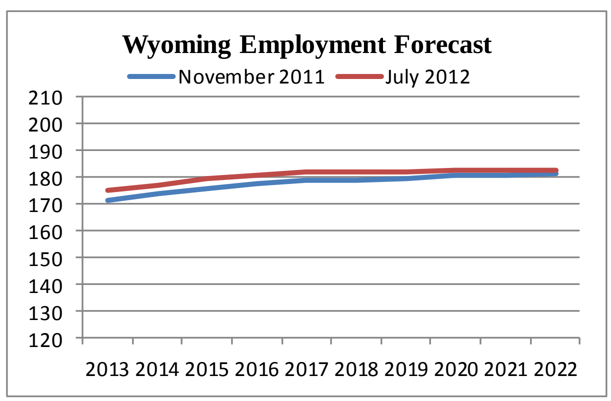


Source: Globe Insight, April 2012

The Company serves 15 of the 23 counties in Wyoming, with the largest metropolitan area served by the Company being Casper, Wyoming. A comparison of the IHS Global Insight forecast for the Wyoming service territory household formation and employment from the 2011 IRP update and the 2013 IRP load forecast is provided in Figure A.8 below.

Figure A.8 – IHS Global Insight Wyoming service territory Household and Employment forecasts from the November 2011 load forecast and the July 2012 load forecast





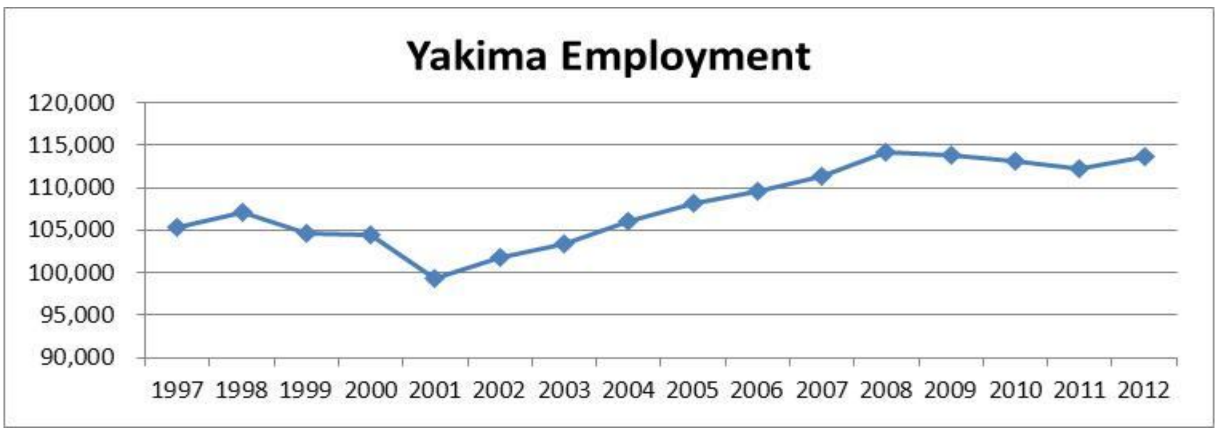
[6] IHS Global Insight.

The national level outlook for household formation was lowered in the February 2012 forecast, which resulted in a lower household forecast for Wyoming. Housing starts in Wyoming will increase over the medium-term, but from low levels, and despite the growth, they will remain below their pre-recession peak levels. Employment growth was stronger than expected in 2011 due to the mining sector, while manufacturing finished weaker. Overall, there was not much change in forecasted job growth in either manufacturing or total employment over the next five years.[7]

Washington

The national recession took its toll on the Washington economy and reduced output and income growth during the end of 2007. Washington's best short-term strength is the presence of large companies such as Boeing and Microsoft, which drive employment growth in their respective industries and also create a local base of skilled labor that generates new companies. Nearly 60 percent of jobs in Washington are in the Seattle metro area, while PacifiCorp serves only the following counties in Washington state: Benton, Columbia, Garfield, Klickitat, Walla Walla, and Yakima. Yakima is the most populated area that the Company serves in Washington State and has a large concentration in agriculture and food processing. Figure A.9 below shows the changes in employment in Yakima since 1997, and the slow economic recovery since the recession.[8]

Figure A.9 – Yakima, WA Metropolitan Statistical Area Employment Statistics, 1997 through 2012

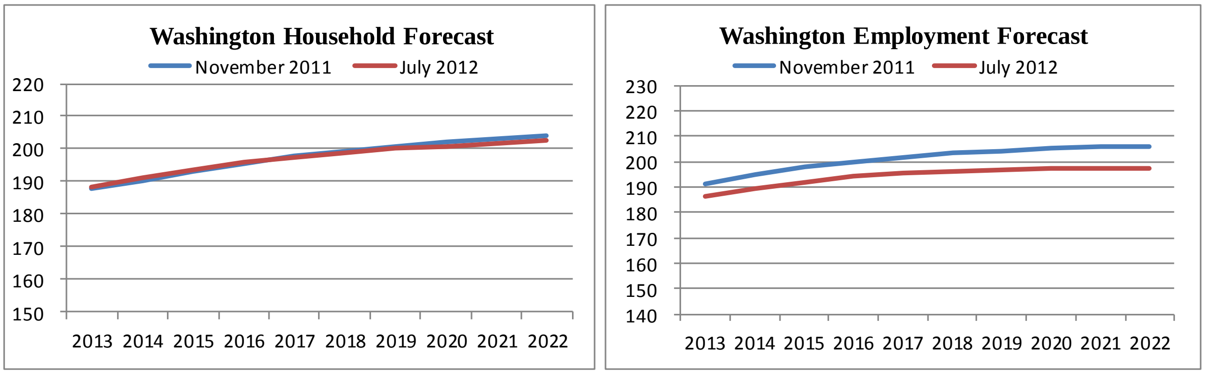


Source: Bureau of Labor Statistics

IHS Global Insight projects near term reductions in gross state product and the food sector was lower than their expectations in 2011, which pushed the forecast lower, especially near 2016. A comparison of the IHS Global Insight forecast for the Washington service territory household formation and employment from the 2011 IRP update and the 2013 IRP load forecast is provided in Figure A.10 below.

[7] *Id.*
[8] *Id.*

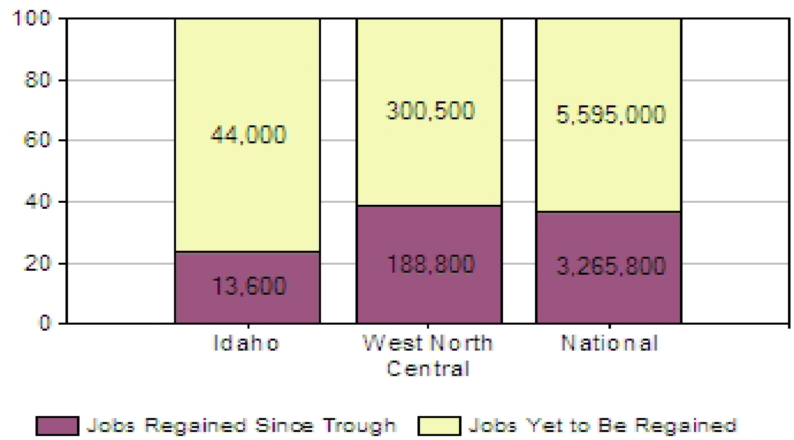
Figure A.10 – IHS Global Insight Washington service territory Household and Employment forecasts from the November 2011 load forecast and the July 2012 load forecast



Idaho

The Company serves 14 of the 44 counties in the state of Idaho, with the majority of the Company's service territory in rural Idaho. Idaho's recession recovery has been difficult, with shut down's in wood product manufacturing in 2009 and overseas job exports in the computer and electronic manufacturing. According to the Idaho Department of Labor, rural counties have been hit hardest in Idaho with a decline of 0.6 percent in gross state product in 2011 while urban counties grew 1.1 percent. Figure A.11 is an illustration of Idaho's economic recovery relative to the West North Central and National regions.

Figure A.11 - Recession Recovery: Changes in Employment (Percent)

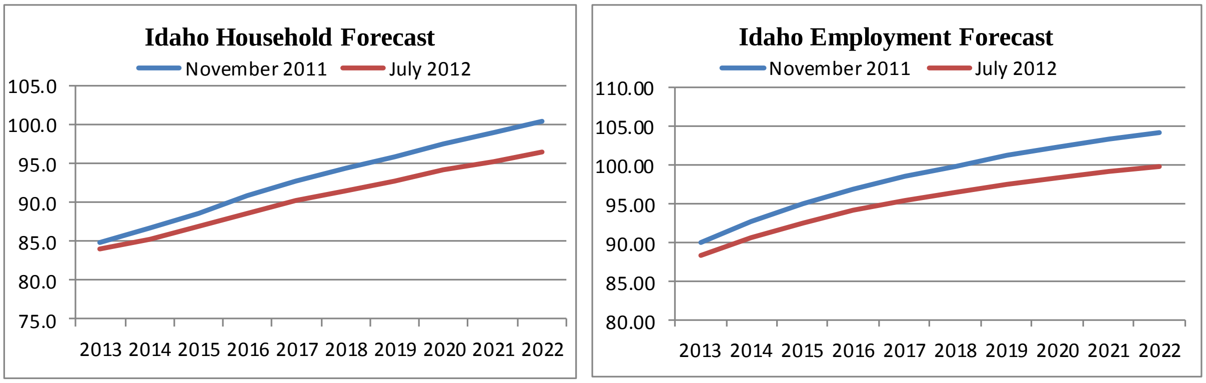


Source: IHS Global Insight, April, 2012

Idaho's household growth has been weaker during the recession, and was therefore lowered in the near-term forecast. The construction sector has continued to lag behind the national economic recovery, but it is starting to show signs of growth.[9]

[9] *Id.*

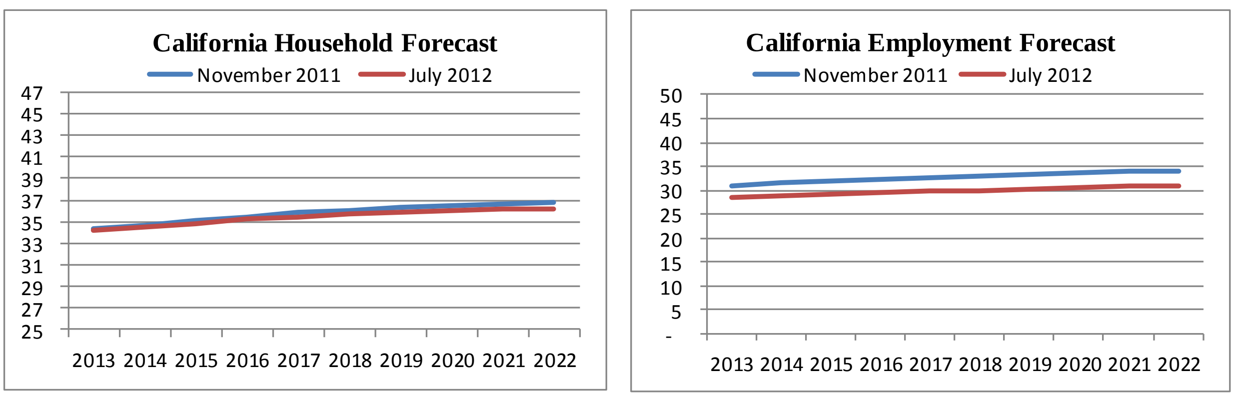
Figure A.12 - IHS Global Insight Idaho service territory Household and Employment forecasts from the November 2011 load forecast and the July 2012 load forecast



California

The California counties served by PacifiCorp are: Del Norte, Modoc, Shasta and Siskiyou. The sectors that will drive growth over the next decade in the northern California counties served by PacifiCorp are the professional and business services, trade and transportation, and construction.

Figure A.13 – IHS Global Insight Idaho service territory Household and Employment forecasts from the November 2011 load forecast and the July 2012 load forecast



Weather

The Company's load forecast is based on normal weather defined by the 20-year time period of 1992-2011. The Company updated its temperature spline models to the five-year time period of 2007-2011. The Company's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

Statistically Adjusted End-Use ("SAE")

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

Individual Customer Forecast

The Company updated its load forecast of a select group of large industrial customers, self-generation facilities of large industrial customers, and data center forecasts within the respective jurisdictions. Customer forecasts are provided by the customer to the Company through a customer account manager ("CAM").

Actual Load Data

The Company uses actual load data from January 1997 through March 2012, except for the industrial class, for its monthly retail sales forecast. The historical data period used to develop the industrial monthly sales is from January 2002 through March 2012.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state that were used in calculating the 2013 IRP retail sales forecast.

Table A.5 Weather Normalized Jurisdictional Retail Sales 1997 through 2012

System Retail Sales - Gigawatt-hours (GWh)*							
Year	**California**	**Idaho**	**Oregon**	**Utah**	**Washington**	**Wyoming**	**System**
1997	768	3,032	13,551	16,647	3,978	7,391	45,367
1998	757	2,994	14,303	16,989	4,027	7,213	46,283
1999	774	3,077	13,736	17,998	4,059	7,250	46,894
2000	782	3,065	14,046	18,806	4,043	7,412	48,154
2001	787	3,003	13,380	18,613	4,005	7,716	47,504
2002	814	3,194	12,997	18,587	3,956	7,318	46,865
2003	836	3,197	13,222	18,997	4,141	7,640	48,033
2004	845	3,291	13,169	19,775	4,075	7,820	48,975
2005	839	3,237	13,209	20,233	4,229	8,028	49,775
2006	847	3,291	13,851	21,070	4,137	8,301	51,497
2007	878	3,400	14,026	21,861	4,060	8,499	52,724
2008	867	3,360	13,756	22,467	4,012	9,307	53,768
2009	827	2,956	13,093	22,053	4,073	9,193	52,195
2010	843	3,357	12,921	22,577	4,047	9,690	53,436
2011	798	3,432	12,923	23,317	3,996	9,771	54,236
2012	780	3,465	12,789	23,624	4,052	9,503	54,214
Average Annual Growth Rate							
1997-2012	0.10%	0.89%	(0.38%)	2.36%	0.12%	1.69%	1.19%

*System retail sales do not include sales for resale

Table A.6 Non-Coincident Jurisdictional Peak 1997 through 2012

Non-Coincident Peak - Megawatts (MW)*						
Year	**California**	**Idaho**	**Oregon**	**Utah**	**Washington**	**Wyoming**
1997	178	697	2,799	3,071	863	1,157
1998	212	686	3,118	3,213	863	1,063
1999	229	711	2,574	3,270	809	1,011
2000	176	686	2,605	3,721	785	1,062
2001	162	616	2,739	3,516	755	1,124
2002	174	713	2,639	3,810	771	1,113
2003	169	722	2,452	4,038	788	1,126
2004	193	708	2,525	3,900	920	1,111
2005	189	753	2,722	4,119	844	1,224
2006	180	723	2,724	4,357	822	1,208
2007	187	789	2,856	4,615	834	1,230
2008	187	759	2,922	4,523	923	1,339
2009	193	688	3,121	4,448	917	1,383
2010	176	777	2,553	4,491	893	1,366
2011	177	770	2,686	4,640	854	1,404
2012	159	800	2,551	4,764	797	1,338
Average Annual Growth Rate						
1997-2012	-0.75%	0.93%	-0.62%	2.97%	-0.53%	0.97%

*Non-coincident peak's do not include sales for resale

Table A.7 Jurisdictional Contribution to Coincident Peak 1997 through 2012

Coincident Peak - Megawatts (MW)*							
Year	**California**	**Idaho**	**Oregon**	**Utah**	**Washington**	**Wyoming**	**System**
1997	174	616	2,799	3,014	843	1,129	7,770
1998	190	647	2,900	3,166	810	1,046	8,354
1999	214	697	2,547	3,242	804	983	7,972
2000	166	651	2,602	3,721	770	1,014	8,480
2001	152	573	2,739	3,514	724	1,091	7,899
2002	162	689	2,621	3,758	771	1,096	8,549
2003	156	594	2,452	4,038	774	1,083	8,922
2004	167	619	2,525	3,869	886	1,098	8,628
2005	173	681	2,501	4,056	844	1,182	8,937
2006	170	666	2,684	4,140	816	1,192	9,322
2007	178	701	2,844	4,473	793	1,230	9,775
2008	171	727	2,903	4,253	865	1,325	9,501
2009	193	517	3,121	4,394	891	1,361	9,420
2010	157	712	2,513	4,371	809	1,336	9,418
2011	154	747	2,510	4,638	798	1,384	9,431
2012	156	782	2,444	4,756	786	1,316	9,831
Average Annual Growth Rate							
1997-2012	-0.73%	1.60%	-0.90%	3.09%	-0.47%	1.03%	1.58%

*Coincident peak's do not include sales for resale

System Losses

System line losses were updated to reflect actual losses for the 5-years ending December 31, 2011.

Forecast Methodology Overview

Class 2 Demand-side Management Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's 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.

Modeling overview

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

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 1997 to March 2012. 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.

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

For the commercial class, the Company forecasts sales per customer using regression analysis techniques with non-manufacturing employment used as the major economic driver, in addition to weather-related variables. As already described, the sales forecast for the residential and commercial classes is the product of the number of customer forecast and the use per customer forecast. The development of the forecast of monthly commercial sales involves an additional step. To reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Company's CAM's. Although the scale is much smaller, the treatment of large commercial additions is similar to the previous methodology for large industrial customer sales, which is discussed below.

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

The majority of industrial customers are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of industrial customers, the largest on the Company's system, the Company individually forecasts these customers based on input from the customer and information provided by the CAM's.

Previously, the Company separated the industrial class into three categories: (1) existing customers tracked by CAMs; (2) new large customers or expansions by existing large customers; and (3) industrial customers that are not monitored by CAMs. The Company developed the forecast for the first two categories through the usage data gathered by the CAMs based on direct input from the customers, forecasted load factors, and the probability of the project occurrence. The third category was forecasted using regression analysis consistent with how the total industrial class is now forecast.

The Company has changed the way that it forecasts the majority of its large industrial customer due to the fact that for existing large industrial customers and for new large industrial customers, the Company found that the inputs provided by customers for their existing loads and for new load tended to be overly optimistic and ultimately overstated. Therefore, the Company uses a regression analysis for the entire industrial class, excluding those largest industrial customers and taking into consideration historical patterns of industrial growth. The Company believes this is a reasonable means of forecasting existing customer load and future growth. The Company continues to monitor new load requests and planned expansions of existing customers for significant changes that would require an adjustment to the forecast.

After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. These weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period 1992 through 2011. Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

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

Sales Forecast at the Customer Meter

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

Table A.8 – System Annual Sales Forecast 2013 through 2022

System Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	15,892,523	16,972,872	19,240,051	1,245,659	141,420	278,110	**53,770,635**
2014	15,891,128	17,304,602	19,495,342	1,245,013	141,650	276,500	**54,354,234**
2015	15,961,243	17,579,339	19,486,869	1,244,379	141,720	275,360	**54,688,910**
2016	16,119,367	17,856,944	19,633,350	1,243,744	142,200	274,640	**55,270,245**
2017	16,178,084	18,036,974	19,858,482	1,242,654	141,830	273,960	**55,731,984**
2018	16,320,488	18,178,182	20,096,253	1,241,766	141,880	273,570	**56,252,140**
2019	16,467,391	18,285,923	20,362,319	1,240,676	141,930	273,270	**56,771,509**
2020	16,631,788	18,452,865	20,663,756	1,239,860	142,380	273,150	**57,403,799**
2021	16,689,586	18,514,785	20,855,752	1,238,940	142,050	272,920	**57,714,033**
2022	16,821,408	18,630,240	21,104,262	1,237,944	142,090	272,810	**58,208,753**
Average Annual Growth Rate							
2013-22	**0.63%**	**1.04%**	**1.03%**	**-0.07%**	**0.05%**	**0.00%**	**0.89%**

Residential

Average annual growth of the residential class sales forecast declined from 0.7 percent in the 2011 IRP to 0.6 percent in the 2013 IRP. Residential use per customer across all six of PacifiCorp's states is changing due to changes in lighting efficiency standards resulting from the 2007 Federal Energy legislation and other energy efficiency and conservation programs.

The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 0.7 percent with Rocky Mountain Power states adding 0.9 percent per year and Pacific Power states adding 0.5 percent per year reaching approximately 1.6 million customer's by 2022. New customer's on PacifiCorp's system will contribute to declining average use of the residential class due to the expectation that new single-family homes are likely to use gas for space and water heating and use more efficient appliances than the existing customer base.

Commercial

Average annual growth of the commercial class sales forecast declined from 1.9 percent annual average growth to 1.0 percent expected annual growth. The Company lowered its data center load expectations in Utah and Oregon in the 2013 IRP load forecast due to lower than expected initial loads and additional energy efficiency gains in the technology industry. Commercial loads related to non-manufacturing employment are also lower, shown by the lower IHS Global Insight forecast used in the July 2012 load forecast relative to the November 2011 forecast.

PacifiCorp commercial customers are expected to grow at an annual average rate of 0.8 percent, reaching 231,818 customers in 2022. Rocky Mountain Power is expected to add commercial customers at 1.1 percent annually, and Pacific Power is forecasted to add 0.4 percent annually.

Industrial

Industrial sales have decreased in the July 2012 load forecast to 1.0 percent average annual growth through 2022. The November 2011 load forecast projected average annual growth of 1.9 percent for the industrial class, which reflected expected growth in the Utah and Wyoming industrial extraction and manufacturing industries.

A portion of the Company's industrial load is in the oil and natural gas business in Utah and Wyoming, therefore, changes in natural gas and oil prices can impact the Company's load forecast. With the decline in natural gas prices over the last several years the Company has seen several large industrial customers cancel expected new loads. Specifically, Wyoming's mining and natural resource sector is facing falling employment and over the past six month's jobs in the sector declined 0.8 percent.[10] In addition, environmental legislation may impact new exploration in the future. However, if natural gas prices were to increase in the short-term the Company may face higher growth rates than currently reflected. The risk to the Company's load forecast due to commodity price changes is reflected in the high economic growth scenario discussed below.

Self-generation elections by some of the Company's largest industrial customer's reduced the load forecast in the 2013 IRP. However, the majority of the load decreases also remove the customer owned qualifying generation facility (QF) as a resource in the load resource balance. For example, if 100 MW of load is now offset by a company's QF generation that was previously used to provide power to the PacifiCorp system, it is a zero net change to the load resource balance.

As previously discussed, PacifiCorp changed the methodology that it uses to forecast the majority of its large industrial customers and uses a regression methodology versus using probability weighted customer forecasts. The change in methodology of the industrial load forecast had a minimal impact on the industrial forecast.

[10] IHS Global Insight.

State Summaries

Oregon

Table A.9 summarizes Oregon state forecasted retail sales growth by customer class.

Table A.9 – Forecasted Sales Growth in Oregon

Oregon Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	5,411,440	5,258,837	2,147,544	238,210	36,750	0	**13,092,781**
2014	5,381,652	5,378,564	2,132,753	238,210	36,940	0	**13,168,119**
2015	5,380,412	5,440,133	2,137,674	238,210	36,960	0	**13,233,388**
2016	5,407,424	5,523,431	2,136,728	238,240	37,070	0	**13,342,893**
2017	5,402,600	5,576,598	2,134,157	238,210	36,960	0	**13,388,526**
2018	5,429,131	5,602,093	2,131,611	238,210	36,960	0	**13,438,005**
2019	5,463,250	5,630,591	2,131,077	238,210	36,960	0	**13,500,088**
2020	5,504,944	5,677,591	2,132,199	238,240	37,070	0	**13,590,044**
2021	5,510,144	5,690,504	2,134,050	238,210	36,960	0	**13,609,867**
2022	5,540,019	5,715,827	2,134,811	238,210	36,960	0	**13,665,827**
Average Annual Growth Rate							
2013-22	**0.26%**	**0.93%**	**-0.07%**	**0.00%**	**0.06%**	**0.00%**	**0.48%**

Washington

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

Table A.10 – Forecasted Sales Growth in Washington

Washington Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	1,604,806	1,393,879	787,342	157,950	9,930	0	**3,953,907**
2014	1,596,722	1,396,080	783,374	157,950	9,870	0	**3,943,996**
2015	1,593,870	1,398,210	779,487	157,950	9,880	0	**3,939,397**
2016	1,601,704	1,402,674	780,101	157,960	9,910	0	**3,952,349**
2017	1,599,472	1,399,530	776,337	157,950	9,880	0	**3,943,170**
2018	1,608,223	1,401,755	775,894	157,950	9,880	0	**3,953,702**
2019	1,617,306	1,403,765	775,473	157,950	9,880	0	**3,964,373**
2020	1,628,171	1,409,972	777,641	157,960	9,910	0	**3,983,654**
2021	1,627,509	1,408,601	775,425	157,950	9,880	0	**3,979,365**
2022	1,634,603	1,410,691	775,362	157,950	9,880	0	**3,988,486**
Average Annual Growth Rate							
2013-22	**0.20%**	**0.13%**	**-0.17%**	**0.00%**	**-0.06%**	**0.00%**	**0.10%**

California

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

Table A.11 – Forecasted Retail Sales Growth in California

California Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	380,422	274,429	24,148	95,740	2,480	0	**777,219**
2014	377,522	274,946	23,399	95,740	2,480	0	**774,087**
2015	376,263	275,410	22,500	95,740	2,480	0	**772,392**
2016	377,322	275,948	22,440	95,760	2,480	0	**773,951**
2017	375,569	275,028	22,247	95,740	2,480	0	**771,063**
2018	376,273	275,115	22,165	95,740	2,480	0	**771,773**
2019	377,028	275,052	22,082	95,740	2,480	0	**772,382**
2020	378,117	275,582	22,074	95,760	2,480	0	**774,013**
2021	375,925	274,252	21,912	95,740	2,480	0	**770,309**
2022	375,445	273,446	21,824	95,740	2,480	0	**768,935**
Average Annual Growth Rate							
2013-22	**-0.15%**	**-0.04%**	**-1.12%**	**0.00%**	**0.00%**	**0.00%**	**-0.12%**

Utah

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

Table A.12 – Forecasted Retail Sales Growth in Utah

Utah Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	6,720,885	7,979,093	7,754,583	187,500	77,610	278,110	**22,997,781**
2014	6,734,483	8,145,495	7,894,805	187,500	77,650	276,500	**23,316,432**
2015	6,782,580	8,315,720	7,753,540	187,500	77,650	275,360	**23,392,350**
2016	6,875,135	8,460,421	7,760,376	187,520	77,870	274,640	**23,635,961**
2017	6,928,116	8,563,743	7,912,169	187,500	77,650	273,960	**23,943,138**
2018	7,015,004	8,648,996	8,054,146	187,500	77,650	273,570	**24,256,866**
2019	7,099,052	8,701,692	8,225,171	187,500	77,650	273,270	**24,564,335**
2020	7,191,309	8,783,756	8,399,911	187,520	77,870	273,150	**24,913,516**
2021	7,241,742	8,820,185	8,525,736	187,500	77,650	272,920	**25,125,732**
2022	7,324,392	8,889,035	8,681,001	187,500	77,650	272,810	**25,432,388**
Average Annual Growth Rate							
2013-22	**0.96%**	**1.21%**	**1.26%**	**0.00%**	**0.01%**	**-0.21%**	**1.12%**

Idaho

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

Table A.13 – Forecasted Retail Sales Growth in Idaho

Idaho Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	705,895	438,865	1,711,758	545,899	2,710	0	**3,405,127**
2014	717,289	448,476	1,716,591	545,153	2,770	0	**3,430,279**
2015	731,279	458,456	1,719,879	544,399	2,810	0	**3,456,823**
2016	748,393	469,083	1,726,161	543,584	2,890	0	**3,490,112**
2017	760,771	476,315	1,720,329	542,504	2,920	0	**3,502,838**
2018	774,717	483,775	1,720,487	541,526	2,970	0	**3,523,475**
2019	787,131	490,076	1,720,573	540,336	3,020	0	**3,541,136**
2020	799,309	497,675	1,725,216	539,330	3,070	0	**3,564,601**
2021	806,807	502,048	1,719,649	538,390	3,140	0	**3,570,035**
2022	816,694	507,401	1,720,681	537,314	3,180	0	**3,585,271**
Average Annual Growth Rate							
2013-22	**1.63%**	**1.63%**	**0.06%**	**-0.18%**	**1.79%**	**0.00%**	**0.57%**

Wyoming

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

Table A.14 – Forecasted Retail Sales Growth in Wyoming

Wyoming Retail Sales – Gigawatt-hours (GWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Other	**Total**
2013	1,069,076	1,627,768	6,814,676	20,360	11,940	0	**9,543,819**
2014	1,083,460	1,661,040	6,944,420	20,460	11,940	0	**9,721,321**
2015	1,096,840	1,691,410	7,073,790	20,580	11,940	0	**9,894,559**
2016	1,109,388	1,725,387	7,207,544	20,680	11,980	0	**10,074,979**
2017	1,111,556	1,745,760	7,293,243	20,750	11,940	0	**10,183,249**
2018	1,117,141	1,766,449	7,391,950	20,840	11,940	0	**10,308,320**
2019	1,123,623	1,784,748	7,487,944	20,940	11,940	0	**10,429,195**
2020	1,129,938	1,808,290	7,606,714	21,050	11,980	0	**10,577,972**
2021	1,127,459	1,819,195	7,678,982	21,150	11,940	0	**10,658,726**
2022	1,130,254	1,833,840	7,770,582	21,230	11,940	0	**10,767,847**
Average Annual Growth Rate							
2013-22	**0.62%**	**1.33%**	**1.47%**	**0.47%**	**0.00%**	**0.00%**	**1.35%**

Alternative Load Forecast Scenarios

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

The July 2012 forecast is the baseline (Medium) scenario. For the high and low economic 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 the oil and gas extraction industries, PacifiCorp applied additional assumptions for the Utah and Wyoming industrial class load forecasts in the high and low scenario. Specifically, the Company analyzed the increased uncertainty of the industrial load forecast as it moves further out in time. In order to capture this increased uncertainty the Company modeled 100 possible annual loads for each year based on the standard error of the medium scenario regression equation. The 100 load values are then ranked and the Company selected the 95th percentile and 5th percentile of the Utah and Wyoming industrial loads for both the low and high growth scenarios. Lastly, in the high growth scenario the Company removed the assumption that a large customer owned generation facility was constructed in 2015.

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

Figure A.14 shows the comparison of the above scenarios relative to the Base Case scenario.

Figure A.14 – Load Forecast Scenarios for 1-in-20 Weather, High, Base Case and Low

APPENDIX B – IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2013 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 ("2011 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.[11]
- Table B.2 – Provides a description of how PacifiCorp addressed the 2011 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 Oregon IRP guidelines, including new guidelines issued in January 2012 for assessing flexible resource demand and supplies.
- Table B.4 – Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 – Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and 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 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 I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public Input Process) fully complies with 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.

[11] California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the Company plan for compliance with the California RPS requirements.

To fill any gap between changes in loads and existing resources, while taking into consideration potential early retirement of existing coal units as an alternative to investments that achieve compliance with environmental regulations, the IRP evaluates a broad range of available resource options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Volume I, Chapters 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results) meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western Interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan in Volume I, Chapter 9 (Action Plan). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. Volume I, Chapter 9 (Action Plan) also provides a progress report on action items contained in the 2011 IRP and 2011 IRP Update.

The 2013 IRP and the related Action Plan are filed with each commission with a request for prompt acknowledgment. Acknowledgment means that a commission recognizes the IRP as meeting all regulatory requirements at the time the acknowledgment 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 acknowledgment standards.

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

California

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. The number of PacifiCorp customers, located in the most northern parts of the state, fall below this threshold. 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 2013, and fully addresses the above report components. The IRP also evaluates demand side management (DSM) using a load decrement approach, as discussed in Volume I, Chapter 6 (Resource Options) and Volume II, Appendix D (Demand-Side Management and Supplemental Resources). 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 planning guidelines issued in January 2007 (Order No. 07-002). The Commission's IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), resource acquisition (Guideline 13), and flexible resource capacity (Order No. 12-013[12]). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgment does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given.

Table B.3 provides detail on how this plan addresses each of the requirements.

Utah

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

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-

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

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 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 March 28, 2012.

Table B.5 provides detail on how this plan addresses each of the rule requirements.

Wyoming

In 2008, Wyoming proposed draft rule 253 for any utility serving Wyoming to file its 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. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.	Wyoming General Regulations, Chapter 2 (Introduction), 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, low-income programs, lost opportunities and capability building.	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.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Frequency	Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.	File biennially.	File biennially.	RMR to be filed at least biennially. Conservation reports to be filed annually. Low income reports to be filed at least annually. Lost Opportunities reports to be filed at least annually. Capability building reports to be filed at least annually.	The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest.
Commission Response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.	Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
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. 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.
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.

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies.. • Avoided cost filing required within 30 days of acknowledgment.	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders • DSM and supply side resources evaluated at "Total Resource Cost" rather than utility cost.	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability. • 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.	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

Table B.2 – Handling of 2011 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
Idaho		
Order No. PAC-E-11-10, p. 10.	[T]he Commission orders the Company to advise the Commission of any changes made to its system-wide IRP methodology or IRP results emanating from the review conducted by another state utility Commission.	PacifiCorp summarizes its IRP methodology in Volume I, Chapter 7 of the 2013 IRP, which is consistent with methods used in the 2011 IRP. While advancements in modeling methods have been implemented, they were done so at the discretion of the Company.
Oregon		
Order No. 12-082, p. 9-10.	We direct PacifiCorp to continue discussions with Staff and other parties, started during review of the company's 2011 IRP, to prepare for the company's next IRP cycle. In particular, we direct PacifiCorp to convene two workshops to address concerns in two related areas. The first workshop should address the development of candidate resource portfolios for the next IRP. PacifiCorp currently uses the System Optimizer model to develop the candidate resource portfolios it will consider in an IRP. The company identifies future scenarios comprised of key model inputs and the System Optimizer model selects an "optimal" resource portfolio for each scenario. We are concerned that the resource portfolio with the best combination of cost and risk for the utility and its ratepayers may not be "optimal" for any one particular scenario. In other words, the best portfolio may be one that performs well across a wide range of future scenarios but is not "optimal" for any one scenario. We are concerned that the process used by PacifiCorp to develop candidate resource portfolios may be limiting the diversity of portfolios considered in the IRP. The second workshop should address the development of the company's load and resource balances for both capacity and energy and the appropriate capacity planning reserve margin. The workshop should also address the development of an IRP action plan that identifies the contribution of each planned resource to the company's capacity and energy balances. In PacifiCorp's IRP it is often difficult to identify the contribution of	PacifiCorp held a "portfolio development roundtable" discussion at the June 20, 2012 public meeting to address the first workshop requirement. The Company outlined its goals to enhance resource diversity among portfolios and requested input from Oregon Commission staff and other meeting participants on an enhanced portfolio development framework. Incorporating stakeholder comments, the Company introduced draft core case definitions at the August 13, 2012 a public meeting and discussed with parties transmission scenarios and benefit analysis. Further discussions on portfolio development were held at the September 14, 2012 public meeting. One outcome of the discussions was PacifiCorp's proposal to include stakeholder-defined portfolio development scenarios to achieve greater resource diversity. A subsequent public meeting was held on January 31, 2013 to review the core portfolio results with an update on modeling results at the February 27, 2013 public meeting. Discussion of stochastic modeling results of portfolios was done at the March 21, 2013 and April 5, 2013 public meetings. Sensitivity case results were reviewed with parties at the April 17, 2013 public meeting. The workshop to discuss the planning reserve margin and development of load & resource balances (both capacity and energy) was held during the August 2, 2012, public input meeting. The major issues identified by public stakeholders for the 2011 IRP planning reserve margin study were addressed through the 2013 IRP study design. The Company held a conference call on September 24, 2012 to discuss planning reserve margin modeling. At the public meeting on November 27, 2013 the study results and recommendation were reviewed by the stakeholders. The Company discussed with parties at the August 2, 2012 public input meeting different ways to report the energy contribution from preferred portfolio resources. Volume I, Chapter 8 (Modeling and Portfolio Selection Results) of the 2013 IRP contains figures showing how preferred portfolio resources contribute to growing loads over time.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
	each planned resource to the energy balance. Our overall concern is that it is difficult to identify how the planned resource actions are matched to meeting the capacity and energy needs of the company.	
Order No. 12-493, p.33.	We expect a utility to fully evaluate all major investments that have implications for the utility's resource mix – including those where the investment will extend the useful life of an asset and where a plant shutdown is an option – in its IRP. Although the IRP process is not a legal prerequisite for a utility to seek recovery of investment in rates, we have repeatedly stated that the IRP process serves as a complement to the rate-making process and reduces the uncertainty of recovery. We give considerable weight to actions that are consistent with an acknowledged IRP, and consistency with the plan is evidence to support favorable rate-making treatment of the action. If a utility seeks rate recovery of a significant investment that has not been included in an IRP, we will hold the utility to the same level of rigorous review required by the IRP to demonstrate the prudence of a project. Regardless of whether a utility intends to use the IRP process for a resource decisions, we expect to be kept informed about anticipated majority utility investment.	The Company has analyzed in the 2013 IRP major environmental investments required to meet known and prospective compliance obligations across PacifiCorp's existing coal fleet. Building upon modeling techniques developed in the 2011 IRP and the 2011 IRP Update, environmental investments specific to individual coal units required to achieve compliance with known and prospective federal and state environmental regulations have been integrated into the portfolio modeling process in the 2013 IRP. Potential alternatives to coal unit environmental investments are considered in the development of *all* resource portfolios developed for the 2013 IRP. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. See Volume I, Chapters 7 (Modeling and Portfolio Evaluation Approach), and Chapter 8 (Modeling and Portfolio Selection Results). In addition to integrating coal unit environmental investment decisions into the portfolio development process, the Company has completed detailed financial analysis of near-term investment decisions in Confidential Volume III of the 2013 IRP.
Utah		
Order, Docket No. 11-2035-01, p. 17.	We generally accept the Company's approach [on externality cost values] and suggest continued discussion in the IRP public input process to determine a reasonable and manageable range of values. This could also include the notion that once a permit has been obtained, the external costs addressed through the permit are internalized; all other values should be treated as uncertainties through scenario development and a range of potential values.	PacifiCorp discussed the approach for modeling externality costs with CO_2 price scenarios. The Company discussed with stakeholders CO_2 price levels and in the context of defining portfolio case definitions and in interpreting model results at several public meetings (6/20/12, 7/13/12, 9/14/12, 1/13/2013, 3/21/2013, 4/5/2013, 4/17/2013). The Company worked closely with stakeholders, adopting numerous recommendations, in defining assumptions for portfolio development cases and sensitivities. Costs for adding pollution control equipment to meet current and potential environmental regulations are explicitly incorporated into the cost for affected generating assets, whether new or existing. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Volume II, Appendix M (Case Study

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
		Fact Sheets).
Order, Docket No. 11-2035-01, p. 15.	[A]ny Potentials Study used to inform the IRP should be filed concurrently with the IRP.	The Demand-side Management Potentials study is posted to PacifiCorp's IRP website, referenced in Volume II, Appendix D (Demand-Side Management and Supplemental Resources).[13] An updated stochastic loss of load probability study prepared by Ventyx, is included in Volume II, Appendix I (Stochastic Loss of Load Study). A 2011 Geothermal Information Request was posted for stakeholder review on PacifiCorp's IRP website.[14] An energy storage screening study for integrating variable energy resources was posted for stakeholder review on the PacifiCorp IRP website.[15]
Order, Docket No. 11-2035-01, p. 21.	The Company should conduct a meeting to explain its development of DSM resource bundles. This meeting could be in an IRP technical conference, a DSM Advisory Group meeting or an IRP public input meeting. The Company should address its plans to closely monitor DSM resource acquisitions for adherence to IRP forecasts in its next IRP.	The topic of modeling energy efficiency resources was covered at the June 20, 2012 public input meeting, and was also discussed at the Utah stakeholder meeting held August 14, 2012. PacifiCorp distributed a paper on energy efficiency ramping assumptions October 10, 2012. Monitoring of DSM resource acquisitions is covered in Volume I, Chapter 9 (Action Plan).
Order, Docket No. 11-2035-01, p. 20.	The Company should consider hosting a public input meeting to discuss the objectives of and options for addressing long-term load volatility and long-term load-growth uncertainty and to respond to the five GDS recommendations. The Company should provide interested parties with any analysis it performs regarding the five GDS recommendations in advance of the meeting. GDS recommendations: 1. PacifiCorp should obtain and examine economic forecasts from one or two vendors in addition to IHS Global Insights. 2. GDS continues to contend that use of a measure of commercial and industrial output (e.g., retail sales or gross regional product) would be a better	PacifiCorp held a public meeting on September 14, 2012, to discuss the GDS report and PacifiCorp's plans for addressing the recommendations.

[13]http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_EnergyEfficiencyResourceRamping_10-22-2012.pdf
[14]http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp_GIR_Report-PUBLIC_04-16-12.pdf
[15]http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/Report_Energy-Storage-Screening-Study2012.pdf

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
	theoretical driver in the commercial and industrial sales models. 3. We recommend that PacifiCorp initiate an investigation into line losses for Utah and Oregon, specifically, and for any other jurisdictions that exhibiting a strong trend over the last seven years and adjust their line loss projections accordingly. 4. GDS recommends the Company review economic range forecasts prepared by other utilities and produce ranges that have greater uncertainty built into them as the forecast horizon expands. 5. GDS recommends the Company move from a 1-in-10 year weather scenario to a 1-in-20 year weather scenario to produce an even more extreme weather case.	
Order, Docket No. 11-2035-01, p. 20.	[W]e have also found the state historic load information contained in IRPs to be valuable and prefer the Company include a ten year history of monthly energy, coincident peak, and non-coincident peak, by state, in all future IRPs.	State historical load information is reported in Volume II, Appendix A (Load Forecast Details).
Order, Docket No. 11-2035-01, pp. 7-8.	For acknowledgement in the future, the Company should provide all stochastic portfolio performance measures for the Preferred Portfolio and identify the additional cost associated with addressing the non-modeled objectives cited by the Company, e.g., social concerns, and cost recovery risk of geothermal resources. As required by Guideline 4.h., the Company should identify who will bear this financial risk, shareholders or customers.	PacifiCorp provided stochastic results for the preferred portfolio in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Volume II, Appendices K (Detailed Capacity Expansion Results) and L (Stochastic Production Cost Simulation Results) provide details on portfolio results and stochastic modeling results. The Company provides costs for additional modeling completed to inform selection of the preferred portfolio in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Order, Docket No. 11-2035-01, p. 13.	The Company should fully vet changes in methods or evaluation criteria with public participants. The public input process schedule needs to be better managed to fully consider comments provided on the draft IRP.	PacifiCorp's portfolio selection methodology and performance criteria were fully vetted with stakeholders at the November 5, 2012 public input meeting. Enhanced modeling methods used in the portfolio development process related to analysis of renewable resources were vetted with stakeholders at the August 13, 2012 public input meeting. DSM modeling improvements were reviewed with stakeholders at the June 20, 2012 public input meeting. Transmission benefit modeling tools were reviewed with Stakeholders at the July 13, 2012, November 5, 2012, and February 27, 2013 public input meetings. Analysis of coal unit environmental investments were reviewed in the context of developing core and sensitivity case definitions, reviewed with stakeholders at several public input meetings. Improvements were made to the public comment and response process, including

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
		establishment of a stakeholder communications Web page for logging comments and PacifiCorp responses. Moreover, opportunities for stakeholder involvement were greatly expanded for the 2013 IRP, which included 15 public input meetings (more than twice the number of meetings held for the 2011 IRP public process), communications with stakeholders through several conference calls, and five state meetings.
Order, Docket No. 11-2035-01, pp. 13-14.	Going forward, the Company, in its next IRP, should spend more effort developing comparable cases and ensuring consistent and comparable evaluation of alternative resources. -- The Company should allow public input for developing a strategy to specify cases, and alternative "future" scenarios. -- The Company should also ensure this strategy provides a sufficient number of cases with common sets of inputs, with consistent assumptions, to perform meaningful comparisons of cases and scenarios. -- The next IRP should identify the cost tradeoffs to achieve different levels of performance with respect to the public interest criteria. -- Criteria the Company previously identified and addressed by manually modifying a given portfolio at the end of the evaluation process should be identified at the beginning of the IRP process. Cases should then be developed and evaluated using all criteria to determine cost, risk and reliability consequences. We will evaluate the success of this approach when the next IRP process concludes.	PacifiCorp worked collaboratively with stakeholders to produce core case definitions applied uniformly among five different Energy Gateway transmission scenarios and to produce sensitivity case definitions incorporating comments from a broad range of stakeholder interests. Comments from stakeholders were logged, responses by the Company generated, and discussion held on core case definitions among three public input meetings (6/20/12, 7/13/12, and 9/14/12). Through this process, the Company solicited specific case definition request from all stakeholders. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of the core and sensitivity case definitions used in the 2013 IRP. Public interest criteria include "resource diversity" and "generator CO_2 emissions". PacifiCorp compared portfolios on the basis of these criteria. Costs for CO_2 emissions are incorporated into portfolios where CO_2 prices are assumed, allowing for a direct comparison of how emissions differences among portfolios contribution to system costs. See Chapter 8 (Modeling and Portfolio Selection Results). The Company did not perform manual modification of portfolios at the end of the portfolio evaluation process. Supplemental analysis, showing cost and risk metrics, were used to inform final selection of the preferred portfolio.
Order, Docket No. 11-2035-01, pp. 13-21.	UAE suggests the next IRP include the cost increase of alternative acquisition strategies. The Company should explore this suggestion. (From UAE comments: ..."the next IRP should also include the estimated increase in cost of the alternative near and long term acquisition strategies" [shown in Table 9.2])	Costs for portfolios, representing alternate acquisition strategies, are summarized in in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) and in Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results).
Order, Docket No. 11-2035-01, 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 Company complies with this directive. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results) as well as Volume II, Appendix K (Detailed Capacity Expansion Results), and Appendix L (Stochastic Production Cost Simulation Results).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
	the consistent and comparable treatment of resources going forward.	
Order, Docket No. 11-2035-01, p. 13.	The Company argues steps to address model transparency will be expensive and time consuming. Rather, the Company recommends stakeholders identify specific modeling or assumption development concerns which the Company could investigate based on a clearly defined scope of work, considering schedules and analytical priorities, in the next IRP. This could involve additional model runs. The Company argues this type of validation strategy would be on-going and makes sense given evolving models and study requirements. We generally concur with the Company's suggested approach for the next IRP.	PacifiCorp and Ventyx established a Ventyx model support opportunity where stakeholders can pay time and material rates for Ventyx to run PacifiCorp's models and answer technical questions on model operations. So far no stakeholders have expressed interest beyond requesting more information on the opportunity.
Order, Docket No. 11-2035-01, p. 11.	UAE [Utah Association of Energy Users] notes IRP 2011 provides no discussion of rate design as required in Guideline 4.g. The Company should include this information in future IRPs.	The information is included in Volume I, Chapter 3 (The Planning Environment).
Order, Docket No. 11-2035-01, p. 10.	We find the Company has provided insufficient information in [the] IRP 2011 regarding the cost impacts to customers associated with the change from geothermal to wind resources in its Preferred Portfolio. This incremental cost of replacing the geothermal resources with wind resources could be included by the Company in its IRP update, along with a statement regarding whether the customer or shareholder should bear this cost.	PacifiCorp's renewable acquisition analysis and strategy is outlined in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Chapter 9 (Action Plan), and in Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results). Geothermal resources, modeled as a power purchase agreement, were not included the top performing portfolios analyzed in the 2013 IRP and are not in the preferred portfolio.
Order, Docket No. 11-2035-01, p. 11.	In its next IRP, the Company should evaluate the geothermal resource cost recovery risk directly. Since the geothermal cost already includes a development cost estimate, the Company in future IRPs could evaluate higher estimates, and compare this risk with the risks of other portfolios. Finally, we note the action plan contains no action item to address the cost recovery risk issue. The Company should also identify the actions it is taking to address this issue i.e., obtaining regulatory or legislative relief in other states, and include an action plan item in the IRP update to this end.	Geothermal resource recovery risk is addressed by assuming that geothermal resource acquisition would be in the form of Power Purchase Agreements (PPA) with size and location of these resources based on data received from a recent Request for Information. See Volume I, Chapter 6 (Resource Options). The Company developed proxy PPA geothermal resources using bids submitted for the all-source RFP for a 2016 resource. Core case C16 includes geothermal PPA resource options as described in Volume I, Chapter 7 (Modeling Results and Resource Analysis) and Volume II, Appendix M (Case Study Fact Sheets).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
Order, Docket No. 11-2035-01, p. 15.	The Company should perform sensitivity and scenario analyses around key renewable resource cost assumptions in its next IRP.	PacifiCorp evaluated the core cases with and without renewable portfolio standard requirements to isolate the effect of these obligations on renewable resource selection. Case definitions also reflected different federal tax incentive assumptions, which influence the cost of new renewable resources. See Volume I, Chapter 7 (Modeling Results and Resource Analysis) and Volume II, Appendix M (Case Study Fact Sheets). In addition stakeholder input influenced cost assumptions for solar resources, which are assumed to experience real de-escalation in cost.
Order, Docket No. 11-2035-01, p. 18.	The Company should continue to provide the western market analysis in support of its reliance on market purchases.	See Volume II, Appendix J (Western Resource Adequacy Evaluation).
Order, Docket No. 11-2035-01, p. 18.	We accept a 13 percent planning reserve as reasonable for this IRP and recommend continued analysis of this issue [of the appropriate PRM level], both through LOLP and tradeoff analysis, and the testing of the 1.5 percent adjustment [for reserve sharing among Northwest Power Pool participants].	See Volume II, Appendix I (Stochastic Loss of Load Study). PacifiCorp's planning reserve margin study focused on estimating the marginal cost of reliability for different planning reserve margin levels, using the stochastic Expected Unserved Energy (EUE) measure. The reliability impact of reserve sharing among Northwest Power Pool members was explicitly incorporated in the production cost modeling.
Order, Docket No. 11-2035-01, p. 21.	The Company should continue to provide sensitivity analysis [on the assumed cost of Energy Not Served] and to discuss this issue in future meetings. This reliability measure is intended to identify the cost differences between portfolios. The Company could host a discussion regarding this measure and the extent to which the ENS measure is accomplishing this goal.	PacifiCorp held a public conference call (9/24/12) and a public meeting (11/27/12) to discuss the methodology and results of planning reserve margin study, one purpose of which is to measure the cost of avoiding Energy Not Served. See Volume II, Appendix I (Stochastic Loss of Load Study). ENS assumptions tied to FERC market cap levels, are incorporated in all portfolio simulations.
Washington		
UE-100514, pp. 3-4.	The next Plan should contain more analysis and discussion of the timing of the acquisition of the resources called for in the Company's preferred portfolio. For instance, the Plan could examine how lower load growth affects resource acquisition or risk-to-market exposure.	This is addressed in the Acquisition Path Analysis section in Volume I, Chapter 9 (Action Plan).
UE-100514, p. 2.	[T]he Company should provide more analysis and explanation of how it intends to meet the RPS requirements in Washington just as it describes the depth of its length (or shortage) in meeting capacity and energy.	The 2013 IRP incorporates a more detailed evaluation of state RPS requirements and compliance strategies including Washington. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) and Chapter 9 (Action Plan). Additional analysis of compliance with Washington's RPS requirements directly informed final selection of the preferred portfolio.
UE-100514, p. 2.	[T]he Company should consider in future Plans the addition of more localized resources, such as anaerobic digesters that may develop in Yakima, Grant, Benton and Franklin counties. Since the Company	Distributed generation resources are addressed in Volume I, Chapter 6 (Resource Options) and Chapter 9 (Action Plan).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2013 IRP
	states that West Control Area resources options reflect its recent cost studies and project experience, we believe it should monitor opportunities to purchase the output of biodigesters in this part of its service territory.	
UE-100514, p. 3.	Wallula to McNary (Energy Gateway Segment A): While we recognize that the Company is obligated to provide sufficient transmission capacity to interconnect such generators pursuant to FERC policies, the IRP should conduct a detailed and separate analysis on how this additional transmission capacity benefits native load customers, whether it is necessary to meet increased load in this service territory or to provide enhanced reliability.	The Company is modeling individual transmission segments. See Volume I, Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), and Chapter 9 (Action Plan) for details on how transmission investments were analyzed in the 2013 IRP and the specific actions the Company will take over the next two to four years based on this analysis.
UE-100514, p. 3.	West of Hemingway (Energy Gateway Segment H): At a minimum, we encourage the Company to participate actively in the various regional and sub-regional transmission planning efforts currently underway that are relevant to Hemingway to better inform its planning.	The Transmission Section, Chapter 4 (Transmission Planning and Investment) addresses all Energy Gateway evaluations and the Company's participation in other regional and sub regional transmission planning efforts.
Wyoming		
The Wyoming Public Service Commission provided the following comment in its Letter Order (Docket No. 20000-394-EA-11, record No. 12813, dated 12/8/2011) on PacifiCorp's 2011 IRP: *Pursuant to open meeting action taken on November 17, 2011, PacifiCorp d/b/a Rocky Mountain Power's 2011 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 2013 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. Volume I, Chapter 4 (Transmission Planning), Chapter 6 (Resource Options), and Chapter 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 load requirements, relative economics, resource size, availability dates, and other factors.

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
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. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Volume II, Appendix K (Detail Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results).
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Cadmus Group's supply curve data developed in 2012 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 Volume I, Chapter 5 (Resource Needs Assessment), Chapter 6 (Resource Alternatives), and Chapter 7 (Modeling and Portfolio Evaluation Approach) as well as Volume II, Appendix D (Demand-Side Management and Supplemental Resources).
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its nominal after-tax WACC of 6.88 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation with the exception of CO_2 emission compliance costs, which are treated as a scenario risk. Additional scenario risk is used to evaluate load sensitivities. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	Resource risk mitigation is discussed in Volume I, Chapter 9 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Volume I, Chapter 3 (The Planning Environment), Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), and Chapter 8 (Modeling and Portfolio Selection Results).
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results), Chapter 9 (Action Plan), and Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
		Simulation Results) 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 (2013-2032) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) 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 hedging is provided in Volume I, Chapter 9 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the Company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Volume I, Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state and federal resource policies and regulations that are summarized in Volume I, Chapter 3 (The Planning Environment). Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides the results. Volume I, Chapter 9 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make	PacifiCorp fully complies with this requirement. Volume I, Chapter 2 (Introduction) provides an overview of the public process, all public meetings held for the 2013 IRP, which are documented in Volume II, Appendix C (Public Input Process).

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
	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.	
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.	2013 IRP Volumes I and II 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. Volume III of the 2013 IRP is confidential and will be protected through the use of a protective order.
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 draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2013 IRP. The materials shared with stakeholders at these meetings, outlined in Volume I Chapter 2 (Introduction), is consistent with materials presented in Volumes I, II, and III of the 2013 IRP report. PacifiCorp requested and responded to comments from stakeholders in developing core case definitions. The Company considered comments received following the April 5, 2013 and April 17, 2013 public input meetings in developing its final plan.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	The 2013 IRP complies with this requirement.
3.b	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.	This activity will be conducted subsequent to filing this IRP.
3.c	Commission staff and parties must complete their comments and recommendations within six months of IRP filing.	This activity will be conducted subsequent to filing this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	This activity will be conducted subsequent to filing this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: (a)Describes what actions the utility has taken to implement the plan; (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 acknowledged action plan.	This activity will be conducted subsequent to filing this 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, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the System Optimizer model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 5 (Resource Needs Assessment) and Chapter 7 (Modeling and Portfolio Evaluation Approach), and Volume II, Appendix A (Load Forecast) for load forecast information.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	See Chapter 5 (Resource Need Assessment) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach)

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
4.d	For gas utilities only	Not applicable
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology	Volume I, Chapter 6 (Resource Options) identifies the resources included in this IRP, and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Volume II, Appendix D (Demand-Side Management and Supplemental Resources) referencing additional information on PacifiCorp's IRP Web, site see footnote 3 of this Appendix B.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs	In addition to incorporating a 13 percent planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix I), the Company used several measures to evaluate relative portfolio supply reliability. These measures (Energy Not Served and Loss of Load Probability) are described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) describes the key assumptions and alternative scenarios used in this IRP. Volume II, Appendix M (Case Study Fact Sheets) includes summaries of assumptions used for each case definition analyzed in the 2013 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 portfolios designed to determine resource selection under a variety of input assumptions in Volume I, Chapters7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) presents the stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	See responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is designed to avoid inconsistencies with state and federal energy policies therefore none are currently identified.
	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	Chapter 9 (Action Plan) presents the 2013 IRP action plan.

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
	attributes of each resource specified as in portfolio testing.	
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 five Energy Gateway transmission project configurations on a consistent and comparable basis with respect to other resources. 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 potential study was completed in 2012, 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 Volume I, Chapter 6 (Resource Alternatives), the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) and the implementation steps outlined in Volume I, Chapter 9 (Action Plan).
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 1 and 3 DSM) on a consistent basis with other resources.
Guideline 8: Environmental Costs		
8.a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility should develop	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). "Medium" assumptions used to define core cases reflect PacifiCorp's base scenario considered to be the most likely regulatory compliance scenario at this time.

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
	several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	Multiple compliance scenarios were used in core case definitions, including ranges in CO2 prices between zero and those assumed to achieve an 80% reduction in power sector emissions by 2050. For modeling purposes, the cost of CO2 emissions are applied as a tax in which there is a cost imputed on each ton of CO2 emissions generated by system resources. This approach is used in recognition that there are a wide range of policy mechanisms that might be used to regulate CO2 emissions in the power sector at some point in the future. Application of CO2 prices as a tax is a means to assign costs to CO2 emissions as a surrogate for a wide range of potential future policy tools, whether implemented as a tax, cap-and-trade program, emission performance standards, or some other policy mechanism. PacifiCorp used both base case and stringent case assumptions for future Regional Haze regulations requiring investments to control nitrogen oxides and sulfur oxides. All cases developed for the 2013 IRP include investments required to achieve compliance with the Mercury and Air Toxics Standards.
8.b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Volume II, Appendix L (Stochastic Production Costs Simulation Results) provides the Stochastic mean PVRR versus upper tail mean less stochastic mean PVRR scatter plot diagrams that for a broad range of portfolios developed with a range of compliance scenarios as summarized in 8.c above. The Company considers end-effects in its use of Real Levelized Revenue Requirement Analysis, as summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and uses a 20-year planning horizon. Early retirement and gas conversion alternatives to coal unit environmental investments were considered in the development of all resource portfolios. Alternate scenarios were applied in the 2013 IRP to capture the possibility of more stringent Regional Haze compliance obligations.
8.c	Trigger point analysis: The utility should identify at least one CO_2 compliance "turning point" scenario, which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of core case definitions. Several of these core case definitions "triggered" portfolios with extensive coal unit retirements and gas conversions that differ substantially from the preferred portfolio. Comparative analysis of results is included in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
	and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	
	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those the preferred and alternative portfolios.	Several portfolios yield system emissions aligned with state goals for reducing greenhouse gas emissions. These cases are summarized in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
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 2013 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 under the section "The Role of PacifiCorp's Integrated Resource Planning". The Company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	See the response to 1.c.3.1 above. Volume I, Chapter 8 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost levels were used to inform the cost/risk tradeoff analysis.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp evaluated several types of distributed generation resources, including combined heat and power (CHP) and solar photovoltaic systems. The results of these evaluations are documented in Chapter 8 (Modeling and Portfolio Selection Results).
Guideline 13: Resource Acquisition		

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. 3. Identify any Benchmark Resources it plans to consider in competitive bidding.	Chapter 9 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 9 (Action Plan). There are no Benchmark Resources in Chapter 9 (Action Plan).
13.b	For gas utilities only	Not applicable
Flexible Capacity Resources		
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.	See Volume II, Appendix F (Flexible Resource Needs Assessment).
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.	See Volume II, Appendix F (Flexible Resource Needs Assessment).
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	See Volume II, Appendix F (Flexible Resource Needs Assessment).

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

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Public Service Commission of Utah responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence reviews of new resource acquisitions will occur during ratemaking proceedings.	Not an IRP requirement as the Commission acknowledges that prudence reviews will occur during ratemaking proceedings, outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the	PacifiCorp’s public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings is provided in Volume II, Appendix C (Public Input Process).

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
	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.	
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) 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 in Utah will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Volume I, Chapter 9 (Action Plan) describes the linkage between the 2013 IRP preferred portfolio and 2013 business plan resources approved in December 2012. 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.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 8 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The Company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on March 31, 2011, and filed this IRP on April 30, 2013, after requesting a one month filing extension. PacifiCorp normally 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	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings is provided in Volume II, Appendix C (Public Input Process).

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
	parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	
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 2013 IRP are provided in Volume I, Chapter 5 (Resource Needs Assessment) and Volume II, Appendix A (Load Forecast Details).
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	Load forecasts are differentiated by jurisdiction and differentiate energy and capacity requirements. See Volume I, Chapter 5 (Resource Needs Assessment) and Volume II, Appendix A (Load Forecast Details). Non-firm off-system sales are not incorporated into the load forecast. Off-system sales markets are included in IRP modeling and are used for system balancing purposes.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Volume II, Appendix A (Load Forecast Details) documents how demographic and price factors are used in PacifiCorp’s load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model using both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Resource options are summarized in Volume I, Chapter 6 (Resource Options).
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Volume I, Chapter 6 (Resource Options). A sensitivity study of demand-response programs (Class 3 DSM) was also conducted and reported in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Volume I, Chapters 6 (Resource Options) and 7 (Modeling and Portfolio Evaluation Approach) contain assumptions and describe the process under which PacifiCorp developed and assessed these technologies and resources.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
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 resources 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. Replacement capacity is considered in the case of early coal unit retirements as evaluated in this IRP as an alternative to coal unit environmental investments. 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 Volume I, Chapter 9 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2013-2032)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Volume I, Chapter 9 (Action Plan). A status report of the actions outlined in the previous action plan (2011 IRP update) is provided in Volume I, Chapter 9 (Action Plan). In Volume I, Chapter 9 (Action Plan) Table 9.1 identifies actions anticipated in the next two years and in the next four years.
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Volume I, Chapter 9 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, extension of federal renewable resource tax incentives and procurement delays.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Volume I, Chapter 6 (Resource Options). 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 Volume I, Chapter 3 (The Planning Environment). ● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). ● Volume II, Appendix G (Plant Water Consumption) of reports historical water consumption for PacifiCorp's thermal plants.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Volume I, Chapter 9 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 6 (Resource Options). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Volume I, Chapter 9 (Action Plan).
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Volume I, Chapter 9 (Action Plan), specifically, 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, taking into consideration a broad range of resource alternatives defined with varying levels of dispatchability. This trade-off analysis is documented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), and highlighted through the use of scatter-plot graphs showing the relationship between stochastic mean and upper-tail mean stochastic PVRR.
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 and costs for complying with current and proposed U.S. EPA regulatory requirements. 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 Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	See Volume I, Chapter 3 (The Planning Environment). The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Volume I, Chapter 6 (Resource Options).
5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2013 IRP. The materials shared with stakeholders at these meetings, outlined in Volume I Chapter 2 (Introduction), is consistent

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
		with materials presented in Volumes I, II, and III of the 2013 IRP report. PacifiCorp requested and responded to comments from stakeholders in developing core case definitions. The Company considered comments received following the April 5, 2013 and April 17, 2013 public input meetings in developing its final plan.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgment of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgment of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines (WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the IRP work plan on March 28, 2012 in Docket No. UE-120416, given an anticipated IRP filing date of March 31, 2013.
(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 3-6 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 requested a one-month filing extension on January 8, 2013 ("PacifiCorp's

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
		Petition for Modification of Filing Date for its Integrated Resource Plan Pursuant to WAC 480-100-238”). PacifiCorp filed the 2013 IRP on April 30, 2013.
(5)	Commission issues notice of public hearing after company files plan for review.	This activity is conducted subsequent to filing this IRP.
(5)	Commission holds public hearing.	This activity is conducted subsequent to filing this IRP.
(2)(a)	Plan describes the mix of energy supply resources.	Volume I, Chapter 5 (Resource Need Assessment) describes the mix of existing resources, while Volume I, Chapter 8 (Modeling and Portfolio Selection Results) describes the 2013 IRP preferred portfolio.
(2)(a)	Plan describes conservation supply.	See Volume I, Chapter 6 (Resource Options) for a description of how conservation supplies are represented and modeled, and Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for conservation supply in the preferred portfolio. Additional information on energy efficiency resource characteristics is available on PacifiCorp’s IRP Web site. See Footnote 3 of this Appendix.
(2)(a)	Plan addresses supply in terms of current and future needs at the lowest reasonable cost to the utility and its ratepayers.	The 2013 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 Volume I, Chapter 5 (Resource Needs and Assessment).
(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 Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Volume I Chapter 8 (Modeling and Portfolio Selection Results).
(2)(b)	LRC analysis considers resource costs.	Volume I, Chapter 6 (Resource Options), provides detailed information on costs and other attributes for all resources analyzed for the IRP.
(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. Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) provides 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 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.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
(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, Volume I, Chapter 9 (Action Plan) covers the following topics: (1) managing carbon risk for existing plants, (2) assessment of owning vs. purchasing power, (3) purpose of hedging, (4) procurement delays and (5) treatment of customer and investor risks. Volume I, Chapter 4 (Transmission) 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.	In Volume I, Chapter 7 (Modeling and Portfolio Evaluation) the IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington. PacifiCorp also evaluated various CO_2 regulatory schemes, including different levels of CO_2 price assumptions and future Regional Haze compliance requierments. The I-937 conservation requirements are also explicitly accounted for in developing Washington conservation resource costs.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See (2)(b) above.
(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 Volume I, Chapter 6 (Resource Options).
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range. Details concerning the load forecasts used in the 2013 IRP (high, low, and extreme peak temperature) are provided in Volume I, Chapters 5 (Resource Needs Assessment) and Volume II, Appendix A (Load Forecast Details).
(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 Volume II, Appendix A (Load Forecast Details) for a description of the load forecasting methodology.
(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 Volume II, 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 2012, 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. The 2012 DSM potentials study is available on PacifiCorp's IRP Web site. See footnote 3 in this Appendix.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2013 IRP
(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 Volume I, Chapter 5 (Resource Needs Assessment).
(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. Volume I, Chapters 6 (Resource Options and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed and assessed these technologies.
(3)(d)	Plan includes an assessment of transmission system capability and reliability; to the extent such information can be provided consistent with applicable laws.	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 explained in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach). 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)	Plan includes integration of the demand forecasts and resource evaluations into a long range integrated resource plan describing the mix of resources that is designated to meet current and project future needs at the lowest reasonable cost to the utility and its ratepayers.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Volume I, Chapter 7(Modeling and Portfolio Evaluation Approach). The portfolio evaluation covers a 20-year period (2013-2032). 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 in Volume I, Chapter 9 (Action Plan), for PacifiCorp's 2013 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 as in Volume I, Chapter 9 (Action Plan).

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 2013 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction) and in Volume II, Appendix C (Public Input Process).

No.	Requirement	How the Guideline is Addressed in the 2013 IRP
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 9 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 5 (Resource Needs Assessment).
D	A study detailing the types of resources considered;	Volume, I 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 2011 IRP Update is presented in Volume I, Chapter 9 (Action Plan). A chart comparing the peak load forecasts for the 2011 IRP, 2011 IRP Update, and 2013 IRP is included in Volume II, Appendix A (Load Forecast Details).
G	The environmental impacts considered;	Portfolio comparisons for CO_2 and a broad range of environmental impacts are considered, including prospective early retirement of existing coal units as an alternative to environmental investments. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection) as well as Volume II, Appendix L (Stochastic production Cost Simulation Results).
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in this IRP.
I	Reserve Margin analysis; and	PacifiCorp's planning reserve margin study, which documents selection of a capacity planning reserve margin is in Volume I, Appendix I (Stochastic Loss of Load Study).
J	Demand-side management and conservation options;	See Volume I, Chapter 6 (Resource Options) for a detailed discussion on DSM and conservation resource options. Additional information on energy efficiency resource characteristics is available on the Company's website. See footnote 3 in this Appendix.

APPENDIX C – 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.

The IRP public process continued with state stakeholder dialogue sessions from July through August 2012. The 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.

In response to stakeholder requests, PacifiCorp has introduced an additional IRP comments website intended for PacifiCorp's IRP public participants only at the following link - (http://www.pacificorp.com/es/irp/irpcomments.html).

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

Stakeholders

- Attorney General of Washington
- Blue Castle Holdings, Inc.
- Bonneville Power Administration
- Brigham Young University
- Citizen's Utility Board of Oregon
- Committee for Consumer Services State of Utah
- Encana Corporation
- enXco
- Energy Trust of Oregon
- Energy Strategies, LLC
- E-Quant Consulting
- First Wind
- GE Energy
- HEAL Utah and Utah Physicians for a Healthy Environment
- Health Environment Alliance of Utah (HEAL)
- Horizon Wind Energy
- Iberdrola Renewables
- Idaho Conservation League
- Industrial Customers of Northwest Utilities
- Interwest Energy Alliance
- Kennecott Utah Copper
- Magnum Energy
- Monsanto Company
- National Renewable Energy Laboratory
- 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
- Sierra Club Environmental Law Program
- Synapse Energy Economics
- The Energy Project
- Utah Associated Municipal Power Systems (UAMPS)
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Industrial Energy Consumers (UIEC)
- Utah Municipal Power Agency (UMPA)
- Utah Office of Consumer Services (OCS)
- Washington Legislature (Representative Dist. 40)
- Western Clean Energy Campaign (WCEC)
- Western Electricity Coordination Council (WECC)
- 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)
- Peter Ashcroft
- Portland General Electric (PGE)
- Ventyx

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

Public Input Meetings

PacifiCorp hosted 15 full-day public input meetings, five public conference calls, and five state meetings during the 2012-2013. During the 2013 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

May 7, 2012 – General Public Meeting

- Introductions
- IRP Group and Support Team
- IRP preparation schedule
- 2013 IRP regulatory compliance
- Public process
- Modeling Methodology Changes
- Resource Acquisition Activities
- 2012 Wind Integration Study
- Action Plan status update: coal, demand-side management, transmission

June 20, 2012 – General Public Meeting

- Energy efficiency modeling workshop
- 2012 Wind Integration Study workshop
- Portfolio development roundtable discussion

July 13, 2012 – General Public Meeting

- Portfolio Case Development
    - "Strawman" portfolio cases
    - Stakeholder comments and next steps
- Transmission Scenarios in Portfolio Case Development
    - Energy Gateway Scenarios
    - Prior perspectives on IRP/transmission
    - Action items and goals from 2011 IRP
    - Inclusion of transmission projects
- Transmission Benefit Analysis
    - Drivers and objectives
    - FERC Order 1000
    - Benefit identification and valuation example

August 2, 2012 – General Public Meeting

- Conservation Voltage Reduction Project Update
- Resource Adequacy Workshop
    - Planning Reserve Margin
    - Load and Resource Balance
- Portfolio Case Development Comment Update

August 13, 2012 – General Public Meeting

- Utility-scale Supply-Side Resources
- Renewable Portfolio Standards
- Wind Integration Study Update

September 14, 2012 – General Public Meeting

- Public Input Meeting Schedule Update

- Environmental Compliance Update
- Portfolio Development Cases
    - Load Forecast
    - IRP Scenarios
- GRD Recommendations
- Load Forecast (continued)
- Capacity Load and Resource Balance

October 24, 2012 – General Public Meetings
- IRP modeling schedule update
- Utility-scale resource option updates
- Wind Integration Study Update
- Planning reserve margin development using the WECC building block approach
- Portfolio development case fact sheets

November 5, 2012 – General Public Meeting
- Transmission benefit evaluation
    - 2011 IRP Action Plan commitment
    - Transmission System Benefits Tool
    - Overview
    - Review of Sigurd-Red Butte benefits evaluation
    - Segment D preview
- Stochastic modeling and preferred portfolio selection approach

November 27, 2012 – General Public Meeting
- Planning reserve margin (PRM) recommendation and study results
- Methodology update overview

January 31, 2013 – General Public Meeting
- Status Update
- Core Case Portfolio Results
- Wind Integration Update

February 27, 2013 – General Public Meeting
- Transmission System Benefits Tool
- IRP modeling and results update
- Class 2 Demand-Side Management supply curves review

March 21, 2013 – General Public Meeting
- Draft Preferred Portfolio Overview
    - Initial screening
    - Final screening
    - Portfolio selection
- Other results
    - PaR RPS analysis
    - PaR Energy Gateway Segment D update

April 5, 2013 – General Public Meeting
- Updated PaR Analysis
- Draft Preferred Portfolio Update
- Action Plan
- Next Steps

April 17, 2013 – General Public Meeting
- Sensitivity Studies
- Draft IRP Document
- DSM Decrement
- Filing Update

April 17, 2013 – Confidential Meeting
- Discussion on Volume 3

Public Conference Call Meetings

August 24, 2012 - Public Conference Call
- Distributed Generation Resource Assumptions

September 24, 2012 – Public Conference Call
- Planning Reserve Margin Methodology
- Price Scenarios / Modeling Methodology
    - Natural Gas
    - Carbon dioxide tax
    - Electricity

October 3, 2012 – Public Conference Call
- Utility-scale costs of single-axis solar PV resources
- Updated Cadmus distributed solar PV memo (September 28th, 2012)

December 6, 2012 – Public Conference Call
- Brief on forthcoming action from U.S. Environmental Protection Agency
- IRP Filing Schedule Update

December 14, 2012 – Public Conference Call
- Smart Grid Update

December 18, 2012 – Public Conference Call
- Update on IRP Filing Schedule
- Update on Core Case Fact Sheets and Price Curve Scenarios

State Meetings

July 11, 2012 – Idaho State Stakeholder Meeting
July 12, 2012 – Wyoming State Stakeholder Meeting
July 19, 2012 – Oregon State Stakeholder Meeting
July 20, 2012 – Washington State Stakeholder Meeting
August 14, 2012 – Utah State Stakeholder Meeting

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 received comments from many of our stakeholders submitted throughout our public process addressing many of the key assumptions and methodologies used in our portfolio evaluations. Stakeholder written comment is noted on the IRP comment website from the following parties:

- Citizen's Utility Board of Oregon
- Encana Corporation
- HEAL Utah and Utah Physicians for a Healthy Environment
- Idaho Public Utility Commission Staff
- Interwest Energy Alliance
- NW Energy Coalition
- Oregon Department of Energy
- Oregon Public Utilities Commission Staff
- Powder River Basin Resource Council
- Renewable Northwest Project
- Sierra Club
- Utah Association of Energy Users
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Office of Consumer Services
- 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 Staff
- Western Resource Advocates

Many of the clarifications and information requested through the written comments, verbal suggestions, public meetings, teleconference calls and data requests, have been incorporated into the final version of the IRP. Many of the Company's inputs were modified based on stakeholder comments received, such as, , Solar photovoltaic costs, Solar water heating costs, higher wind capacity factors, the geothermal request for information (RFI), DSM Ramping, DSM cost bundles, suggestions for study assumptions, recommendations on development of portfolio cases, and prioritization of case studies. In addition, the technical review committee has provided comments on the wind integration study.

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.

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APPENDIX D – DEMAND-SIDE MANAGEMENT AND SUPPLEMENTAL RESOURCES

Introduction

Appendix D reviews the studies and reports used to support the demand-side management and supplemental resource information used in the modeling and analysis of the 2013 Integrated Resource Plan (IRP).

Class 2 Demand-Side Management Resource Ramping

This document presents the methods used by The Cadmus Group, Inc. (Cadmus) and the Energy Trust of Oregon (Energy Trust) to develop reasonable estimates of annual Class 2 Demand-Side Management (DSM) (energy-efficiency) potential available for acquisition in PacifiCorp's service territory for consideration in PacifiCorp 2013 IRP. The Energy Trust method is applied to resources in Oregon while the Cadmus method applies to the other five states PacifiCorp serves. Though the mechanics of the two methods differ, the objectives are the same – to estimate the amount of reasonably achievable Class 2 DSM potential in each year of the 20-year study period.

Please find the report at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_EnergyEfficiencyResourceRamping_10-22-2012.pdf

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources

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

This study, conducted by Cadmus, in collaboration with Nexant, Inc., primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over a 20-year planning horizon, beginning in 2013. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder resource acquisition. Study results were incorporated into PacifiCorp's 2013 IRP and will be used to inform subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed in 2007 and 2011.

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice. These resources can be defined as: Class 1 DSM (firm, capacity focused), Class 2 DSM (energy efficiency), Class 3 DSM (non-firm, capacity focused), and Class 4 DSM (educational).

From a system-planning perspective, Class 1 DSM resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral changes, resulting from voluntary educational programs included in Class 4 DSM, tend to be the least reliable. With respect to customer choice, Class 1 DSM and Class 2 DSM resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to flow. Class 3 and Class 4 DSM activities involve greater customer choice and control. This assessment estimates potential from Class 1, 2, and 3 DSM.

In addition to the three DSM resource classifications, this study also estimates potential from supplemental resources, which fall outside PacifiCorp's classification of DSM and include renewable and nonrenewable customer-sited generation. For this study, supplemental resources include: combined heat and power (CHP), solar photovoltaics (PV), and solar water heaters (SWH).

This study excludes an assessment of Oregon's Class 2 DSM potential and supplemental resource potential for SWHs, as this potential has been captured in assessment work conducted by the Energy Trust, which provides energy-efficiency potential in Oregon to PacifiCorp for resource planning purposes.

The study can be found at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf
The appendices for the study can be found at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_Vol-II_Mar2013.pdf

Class 3 Demand Side Management load impact market survey study

In its 2011 IRP, PacifiCorp did not include Class 3 options as a base resource for planning purposes. In its action plan update, PacifiCorp committed to have a third-party consultant review and report on how other utilities treat price-responsive products in their resource planning process, and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively.

To inform the treatment of Class 3 in PacifiCorp's 2013 IRP, PacifiCorp engaged Cadmus , to conduct a survey addressing how other utilities typically incorporate the incremental load impact of similar, non-dispatchable, demand response/focused DSM resources (Class 3) in their integrated resource plans. This memorandum reports the results of that survey.

The memo can be found at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_TOUMemo-09-04-2012.pdf

Other Supplemental Resource Studies

Combined Heat and Power study

Cadmus, under contract to PacifiCorp, prepared a study that calculated the levelized cost and produced supply curves for combined heat and power (CHP) systems projected to be installed in PacifiCorp territory over the next 20 years as part of the 2013 IRP. The Cadmus memo in particular completed the following: 1) explain the sources referenced for this analysis, 2) present data used in the analysis, and 3) provide the results.

Cadmus presented draft results to stakeholders on August 24, 2012. Stakeholder input was considered in refining the analysis. The final results were presented in a memo, with responses to stakeholder comments included at the end.

The memo can be found at following:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_CHP-Memo-LCOEexcel_10-04-12.pdf

Solar Water Heating Market Potential and Associated Cost study

Cadmus, under contract to PacifiCorp, calculated the total market potential and associated levelized cost for SWH systems projected to be installed in PacifiCorp territory over the next 20 years. The results of this analysis are used in PacifiCorp's 2013 IRP.

This memorandum discusses the assumptions, data sources, results, and updates to Cadmus' analysis. It also addresses the feedback from the public stakeholder meeting held on August 24, 2012, at which preliminary results were presented.

The memo can be found at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PAC%202013IRP_SWH%20Memo_10-05-12.pdf

Solar Photovoltaic Market Potential and Associated cost study

Cadmus, under contract to PacifiCorp, calculated the predicted technical potential, market potential, and levelized cost of energy for PV systems installed and operating in PacifiCorp territory from 2013-2032. The results of this analysis are used in PacifiCorp's 2013 IRP.

This memorandum outlines the assumptions, data sources, and preliminary results of Cadmus' analysis. Preliminary results were discussed at a stakeholder meeting on August 24, 2012. Based on feedback received at that meeting, this memorandum reflects relevant updates to assumptions, methodology, and results.

The memo can be found at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PAC_2013IRP_Memo_PVInputs_09282012.pdf

APPENDIX E – CONSERVATION VOLTAGE REDUCTION

Introduction

Conservation Voltage Reduction (CVR) and Voltage Optimization (VO) have seen renewed industry interest in recent years as stakeholders strive to experience greater system efficiencies. These terms refer to the reduction in energy usage realized by operating the distribution system and customer equipment at a reduced, but still satisfactory, voltage. In response to a voter-approved initiative in Washington, PacifiCorp (the Company) began detailed analysis of distribution circuits there in order to ascertain what energy savings might be achievable from CVR. Commission staff in Oregon also requested the Company screen distribution circuits in its other major states to determine whether cost effective energy savings potential existed elsewhere in the Company's service territory. The Company's recent progress in CVR analysis has centered on the four areas described below.

Washington Tier 1 study (2011)

The scope of this study was to identify all cost-effective, reliable and feasible system improvements on 19 circuits at 12 substations in Yakima, Sunnyside and Walla Walla. The circuits were chosen based on what the Company thought would be likely to yield energy savings from voltage reduction. In some cases the analyzed circuits were adjacent to[16] other circuits not part of the study, which generated improvement recommendations which could not be incorporated without additional analysis. Three different levels of investment (*low-cost* non-capital improvements, *medium-cost* capital improvements and *high-cost* communication-based capital improvements) were studied to determine whether additional investment could be justified by the associated incremental energy savings.

Fourteen of the nineteen circuits showed potential for cost-effective energy savings, and four of them were chosen for the 2012 pilot implementation. The other ten were adjacent to unstudied circuits. Implementation on these would be postponed until the adjacent circuits could be studied, in order to avoid risk[16] and quantify any additional savings.

The completed study and subsequent CVR factor adjustments based on customer classes yielded a net forecast of 0.24 aMW in energy savings from the recommended projects (0.09 aMW from the four pilot circuits (Clinton substation in Yakima and Mill Creek substation in Walla Walla) and 0.16 aMW from the other ten circuits).

The recommended improvements on the four pilot circuits included a total of eleven single phase swaps (two on 5Y608, four on 5Y610 and five on 5W127) and the addition of one line capacitor

[16] "Adjacent circuits" refers to multiple circuits regulated by the same device. For instance, if Circuits C1 and C2 are regulated by Regulator R1, C1 may have been studied in detail because it was a short urban circuit. Circuit C2 may not have been studied because it was long or had existing low voltage issues. Recommended improvements for Circuit C1 might include minor improvements and a lower voltage setting. There is a risk that Circuit C2 would be adversely affected by the lower voltage setting, and therefore C1 and C2 should be studied together. In the Tier 1 study, the Company picked what it thought were the most promising circuits to determine the magnitude of potential energy savings in the region. In those cases where improvements were forecast to be cost effective and adjacent circuits had not been included, the group of circuits was added to the Tier 2 study.

(600 kVAR on 5W127). Substation voltage band centers, 121 volts at Clinton and 122.75 volts at Mill Creek, were lowered to 119 volts. The median band center in Washington is 121 volts. Interval metering at the start and end of each feeder was also included.

Washington Tier 2 study (2012)

The scope of this study, defined after the Tier 1 study was complete, was to identify all cost-effective, reliable and feasible system improvements on 25 circuits in Yakima and Sunnyside. All Walla Walla savings had been identified. Eleven of the 25 chosen circuits had been studied in Tier 1; the other 14 were adjacent to those eleven. In sum, nine regulated substation buses were studied at seven substations: Grandview, Nob Hill, North Park, Orchard, River Road, Sunnyside and Wiley.

Of the nine buses, three were identified as potentially cost effective for voltage reduction improvements given the assumptions in the study. The forecast energy savings were 0.10 aMW at Orchard substation (two buses) and 0.07 aMW at Sunnyside substation (one bus).

The primary reason for the difference in results between studies is the analysis of adjacent circuits. As an example, North Park substation's 5Y356 was predicted to yield cost-effective savings in Tier 1. When studied with the adjacent 5Y398 in Tier 2, no cost-effective solution for the pair existed. The improvements necessary to make 5Y398 compliant with voltage reduction were high enough to cause the pair of circuits to be non-cost effective.

Washington pilot project results

Of the 0.09 aMW predicted to be acquired through the four 2012 pilot circuits, less than 0.01 aMW was achieved. All four circuits failed to meet the protocol efficiency thresholds both before and after voltage reduction. This meant that energy savings could not be verified by an approved method, since the Simplified Protocol scope requires that the thresholds be met. The estimated savings from the metered data, ignoring the threshold violations, is 0.017 aMW at Clinton and zero or negative energy savings at Mill Creek.

The Clinton pilot was not cost effective. Less than half of the anticipated reduction in average voltage was achieved, and the estimated cost of energy savings was $112.49/MWh, a value 23% higher than the marginal (avoided) purchase energy rate used in Washington. These values come with the caveat that protocol thresholds were violated and confidence in both the voltage reduction value and energy savings value are consequently very low. For the purposes of reporting savings toward the Company's 2012-13 conservation target[17] in Washington, zero energy savings will be claimed for both Clinton and Mill Creek on account of the threshold violations and resulting inapplicability of protocol scope.

[17] In Washington, the Company files its ten-year achievable conservation potential and biennial conservation target every two years. For the 2012-13 biennium, the target for the distribution efficiency portion of the portfolio was filed as a range (0 to 0.346 aMW), because the ability of the Company to achieve its forecast voltage reduction energy savings was unknown.

Multi-state high-level screening effort

Using the results of both studies, a statistical principal component analysis of circuit parameters and energy availability was conducted in 2012 and early 2013. Using system knowledge and sound engineering principles, strong correlations were found between cost-effective energy savings and key indicators such as maximum circuit length, total line miles and residential energy usage.

Two key lessons from the studies and subsequent screening effort are:

1. Most of the Company's circuits are already operating at a relatively low voltage and improvements necessary to allow an even lower voltage are not usually justified by the value of the energy saved.
2. Small amounts of saved energy on the utility system cannot be accurately and repeatedly measured due to the dynamic interplay between the system and the customers' requirements.

In 2012 and 2013, 100% of the active distribution circuits in Oregon, Idaho, Wyoming and Utah were screened by the statistical method described above, and pilot project results were applied where possible to ensure realistic projections. Without identifying the improvements required, this analysis suggests that between 0 and 0.2 aMW of CVR energy savings might exist within the Company's service territory in those four states. The cost of this energy is likely to exceed the Company's marginal purchase cost, and accurate measurement does not appear to be possible at this time.

Future Conservation Voltage Reduction

Future investment decisions regarding voltage reduction as an energy resource must take into account the cost effectiveness, reliability and feasibility of such project. The Company will not pursue distribution efficiency projects that do not meet all three of these criteria. The 2012 pilot on four of the most promising circuits in Washington shows that voltage reduction as a distribution efficiency measure is not cost effective at PacifiCorp.

With regard to reliability of energy savings from voltage reduction, the pilot has also provided valuable information. Actual energy savings appear to be less than one tenth of that predicted by rigorous and detailed system analysis. The Tier 2 study also called out limitations in circuit analysis as a project risk. Additionally, future system reconfiguration needs identified around Clinton substation highlight the danger of long-term energy savings predictions. At this time, energy savings from voltage reduction cannot be reliably acquired at PacifiCorp.

With regard to feasibility of energy savings from voltage reduction, the pilot has helped the Company to better appreciate the difficulty in accurately predicting feeder voltages at varying load levels. State estimation and Advanced Metering Infrastructure research conducted by the Electric Power Research Institute and the Institute of Electrical and Electronic Engineers Energy in 2012[18] highlighted the critical nature of this industry hurdle. The Tier 2 report also acknowledged that load variations create challenges in measuring small voltage and energy

[18] R.F. Arritt, R.C. Dugan, R.W. Uluski and T.F. Weaver, "Investigating Load Estimation Methods with the Use of AMI Metering for Distribution System Analysis," IEEE, 978-1-4673-0338, 2012.

changes. Without more accurate load allocation and voltage modeling technology, the Company has concluded that energy savings from voltage reduction cannot be feasibly measured on its system at this time.

APPENDIX F – FLEXIBLE RESOURCE NEEDS ASSESSMENT

Introduction

In its Order No. 12013 issued on January 19, 2012 in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging," the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

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

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

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

In this appendix, the Company first identifies its flexible resource needs for the IRP study period of 2013 through 2032, as well as the calculation method used to estimate the requirements. Then, the Company identifies its supply of flexible capacity in accordance with the Western Electricity Coordinating Council (WECC) operating reserves guidelines from its generation resources and demonstrates that PacifiCorp has sufficient flexible resources to meet its requirements.

Flexible Resource Requirements Forecast

PacifiCorp estimated its flexible resource needs as being its requirements for operating reserves over the planning horizon to maintain reliability and in compliance with the North American Electric Reliability Corporation (NERC) regional reliability standards. NERC regional reliability standard BAL-STD-002-0[19] requires each balancing authority, such as PacifiCorp East and PacifiCorp West, to carry sufficient operating reserve at all times. Operating reserve consists of contingency reserve and regulating margin. Each of these types of operating reserves is further defined below.

Contingency Reserve

Contingency reserve is the capacity of resources that a balancing authority holds in reserve that can be used to respond to contingency events on the bulk power system (e.g., an instantaneous trip of a large generator). The amount of required contingency reserve is defined in NERC BAL-STD-002-0. Contingency reserve may not be applied to manage other system fluctuations such

[19] http://www.nerc.com/files/BAL-STD-002-0.pdf

as changes in load or output from variable energy resources, which are mainly wind generation resources on PacifiCorp's system.

Regulating Margin

Regulating margin is the additional capacity that a balancing authority holds in reserve to ensure that it has adequate reserves at all times to meet the NERC Control Performance Criteria in BAL-007-1[20]. In the current IRP, regulating margin is composed of ramp reserve and regulation reserve, which are discussed in more details in Volume II, Appendix H, PacifiCorp's 2012 Wind Integration Study. Briefly,

> Ramp Reserve: This category of reserves is to follow net balancing area load changes from minute-to-minute, hour-to-hour continuously at all times. The variability in net balancing area load is assumed to be perfectly known for future time intervals (as though the operator would know exactly what the net balancing area load would be a minute from now, ten minutes from now, and an hour from now) defines the ramp of the system.
>
> Regulation Reserve: Variations in load or wind generation from their respective forecasts are not considered contingency events, yet these events still require generating capacity be set aside in order to follow the variations.

As operating reserves include separate and distinct components, PacifiCorp estimated the forward requirements for each component separately. The contingency reserve requirements are from the stochastic simulation study of the preferred portfolio in the Planning and Risk model, as it is affected by the hourly interchange and generation dispatch represented in the study. The regulating margin requirements, which reflect the additional reserve capacity requirement from the flexible resources and are part of the inputs to the Planning and Risk model, are calculated applying the methods developed in PacifiCorp's 2012 Wind Integration Study (Volume II, Appendix H). Given the similar requirements of regulating margins in terms of response time, they are grouped together with spinning reserves for modeling in this IRP. PacifiCorp has two balancing authority areas, east and west. The reserve requirements for the two balancing authority areas are shown in Table F.1.

[20] NERC Standard BAL-007-1: http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf.
WECC Operating Committee extended the field trial for one year at the meeting on February 8, 2013: https://www.wecc.biz/committees/StandingCommittees/MIC/10102012/Lists/Presentations/1/OC%20Oct%202012%20Highlights%20-%20Paul%20Rice.pdf

Table F.1 - Reserve Requirements (MW)

Year	East		West	
	Spin Req	Non-Spin Req	Spin Req	Non-Spin Req
2013	435	194	329	209
2014	443	199	332	211
2015	467	221	334	212
2016	457	214	337	214
2017	462	218	339	215
2018	468	222	342	217
2019	474	226	342	218
2020	480	230	344	219
2021	487	234	346	220
2022	493	238	347	221
2023	498	242	349	222
2024	540	246	350	223
2025	564	250	352	224
2026	571	254	354	225
2027	577	258	355	226
2028	581	261	357	227
2029	586	265	359	229
2030	591	268	359	229
2031	598	273	357	227
2032	599	274	362	231

Flexible Resource Supply Forecast

Requirements by NERC and the Western Electricity Coordinating Council (WECC) dictate types of resources that can be used to serve reserve requirements. At least one half of the contingency reserve requirements must be spinning reserves, and the remainder is non-spinning reserves:

- Spinning reserves can only be served by resources currently online and synchronized to the transmission grid.

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

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

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

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserves provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired thermal resources, the amount of reserves can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserves are served from not only existing coal- and gas-fired resources that the Company operates, but also from Lake Side 2 that will be online in 2014 and the additional new gas-fired resources selected in the preferred portfolio.

Table F.2 lists the annual capacity of resources that are capable of serving reserves on the east and west side of PacifiCorp's system. All the resources included in the calculation are capable of providing spinning reserves, which can also be used to serve non-spinning reserves. The non-spinning reserve resources under contract with third parties are excluded in the calculations. The changes in supply reflect retirement of existing resources, addition of new preferred portfolio resources, variation in hydro capability due to stream-flow conditions, and expiration of contracts for capacity from the Mid-Columbia projects that are reflected in the preferred portfolio.

Table F.2 - Flexible Resource Supply Forecast (MW)

Year	East Supply	West Supply
2013	1,086	586
2014	1,181	764
2015	1,150	756
2016	1,150	753
2017	1,150	760
2018	1,151	749
2019	1,151	738
2020	1,150	722
2021	1,150	706
2022	1,150	732
2023	1,149	728
2024	1,341	722
2025	1,341	722
2026	1,341	722
2027	1,340	718
2028	1,607	726
2029	1,608	722
2030	1,949	722
2031	1,948	718
2032	2,039	722

Figures F.1 and F.2 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas. The graphs clearly demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements through the IRP planning period.

Figure F.1 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

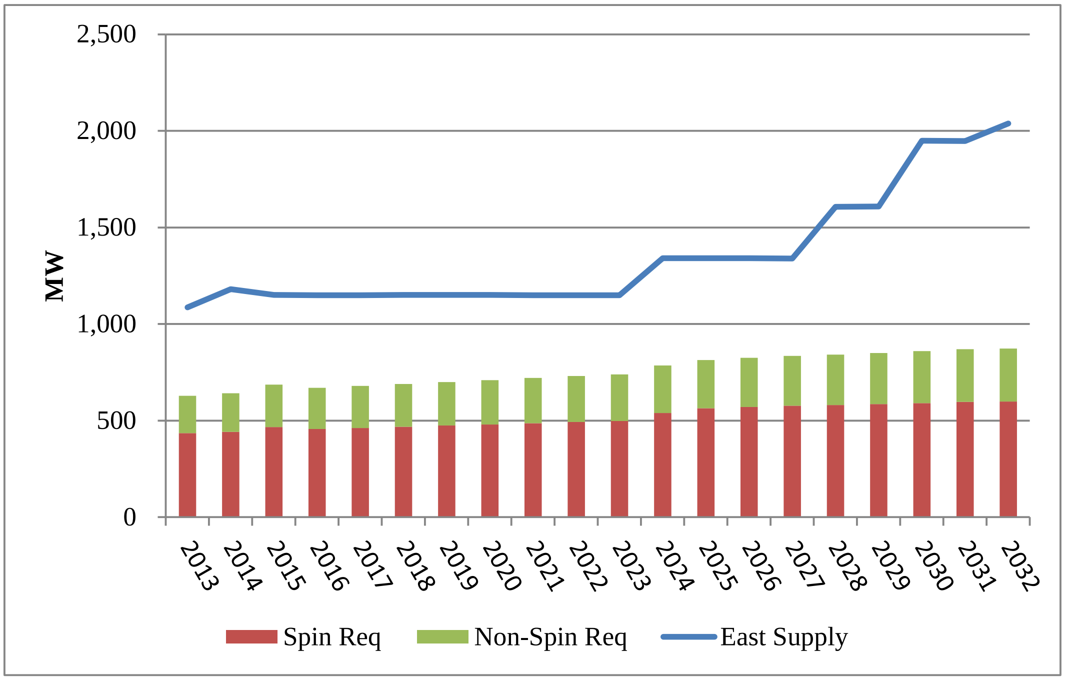
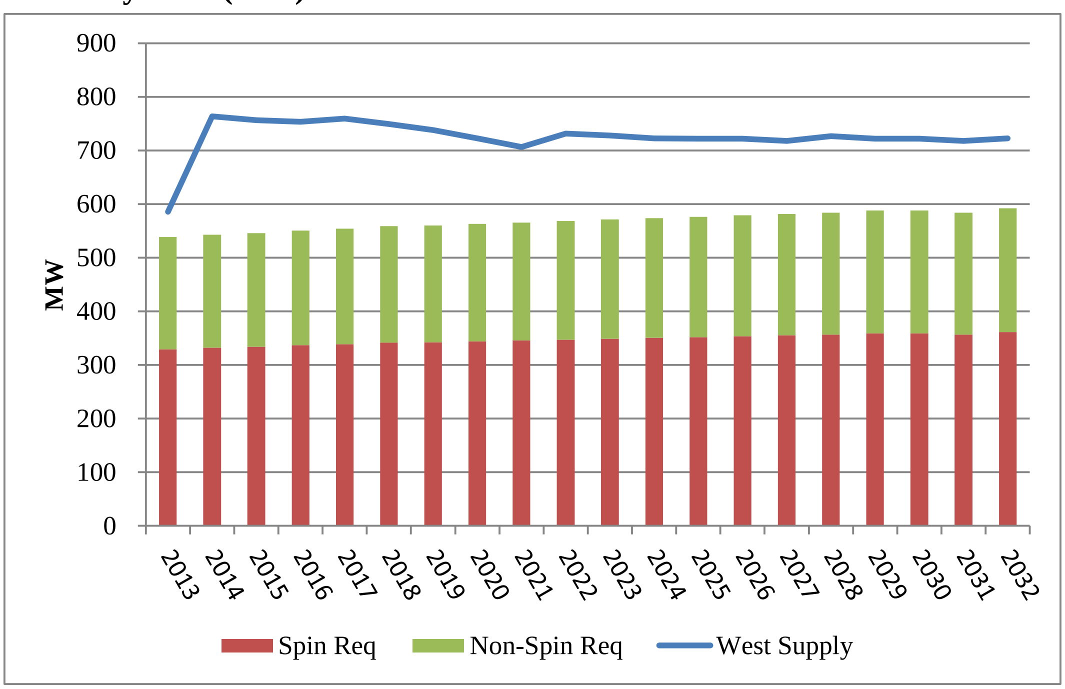


Figure F.2 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

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

In addition, as discussed in Volume I, Chapter 3 of the 2013 IRP report, PacifiCorp has signed a memorandum of understanding with the California Independent System Operator Corporation February 12, 2013 to outline terms for the implementation of an energy imbalance market (EIM) by October 2014. The implementation of the EIM is expected to provide alternatives to more economic dispatch of PacifiCorp's resources and may eventually reduce regulating margin requirements.

As indicated in the OPUC order, electric vehicle technologies may be able to meet flexible resource needs at some point in the future. However, given the electric vehicle technology and market have not been developed sufficiently to provide data for the present study, and given PacifiCorp's analysis shows there is no gap between projected demand and supply of flexible resources over the IRP planning horizon, PacifiCorp's study has not attempted to specifically address how electric vehicles could be used to meet future flexible resource needs.

APPENDIX G – 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 G.1 – Plant Water Consumption with Acre-Feet Per Year

			Acre-Feet Per Year					MWhs Per Year					
Plant Name	Zero Discharge	Cooling Media	2008	2009	2010	2011	Average	2008	2009	2010	2011	Gals/ MWH	GPM/ MW
Carbon		Water	2,199	2,349	2,193	2,458	2,300	1,204,984	1,211,875	1,296,004	1,332,218	594	9.9
Chehalis		Air	-	-	-	-	-	715,441	1,750,041	1,296,741	664,323	-	-
Currant Creek	Yes	Air	82	108	82	78	88	2,799,585	2,464,463	2,536,660	2,397,142	11	0.2
Dave Johnston		Water	7,746	6,983	6,604	7,233	7,141	5,638,807	5,017,794	4,704,694	5,059,927	456	7.6
Gadsby **		Water	426	680	893	864	716	482,903	607,387	359,404	194,389	567	9.5
Hunter	Yes	Water	19,380	19,300	18,941	16,961	18,645	10,246,965	9,438,683	8,785,827	8,719,300	653	10.9
Huntington	Yes	Water	11,385	10,922	9,549	9,069	10,231	7,148,850	6,753,764	6,107,379	5,961,371	513	8.6
Jim Bridger	Yes	Water	27,322	25,361	20,757	22,282	23,931	15,303,508	15,188,184	14,828,906	12,771,611	537	8.9
Lake Side		Water	1,821	1,287	1,533	1,154	1,449	2,863,246	2,099,013	2,537,046	1,845,528	200	3.3
Naughton		Water	10,992	10,846	13,354	14,157	12,337	5,114,409	4,752,632	5,339,385	5,102,251	754	12.6
Wyodak	Yes	Air	446	365	396	367	393	2,811,590	2,732,796	2,565,341	1,831,459	48	0.8
TOTAL			**81,799**	**78,201**	**74,302**	**74,622**	**78,101**	**54,330,288**	**52,016,632**	**50,357,387**	**45,879,519**	**497**	**8.3**

**Gadsby includes a mix of both rankine steam units and peaking gas turbines
Plants Owned and Operated by PacifiCorp
Total water consumption and generation includes all owners for jointly-owned facilities

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

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

UTAH PLANTS				
Plant Name	**2008**	**2009**	**2010**	**2011**
Carbon	2,199	2,349	2,193	2,458
Currant Creek	82	108	82	78
Gadsby	426	680	893	864
Hunter	19,380	19,300	18,941	16,961
Huntington	11,385	10,922	9,549	9,069
Lake Side	1,821	1,287	1,533	1,154
TOTAL	**35,293**	**34,646**	**33,191**	**30,583**

Percent of total water consumption = 43.3%

WYOMING PLANTS				
Plant Name	**2008**	**2009**	**2010**	**2011**
Dave Johnston	7,746	6,983	6,604	7,233
Jim Bridger	27,322	25,361	20,757	22,282
Naughton	10,992	10,846	13,354	14,157
Wyodak	446	365	396	367
TOTAL	**46,506**	**43,555**	**41,111**	**44,039**

Percent of total water consumption = 56.7%

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

COAL FIRED PLANTS						
Plant Name	**2008**	**2009**	**2010**	**2011**	**Generation Capacity**	**Ac-ft/MW**
Carbon	2,199	2,349	2,193	2,458	172	13.4
Dave Johnston	7,746	6,983	6,604	7,233	762	9.4
Hunter	19,380	19,300	18,941	16,961	1,341	13.9
Huntington	11,385	10,922	9,549	9,069	903	11.3
Jim Bridger	27,322	25,361	20,757	22,282	2,118	11.3
Naughton	10,992	10,846	13,354	14,157	700	17.6
Wyodak	446	365	396	367	335	1.2
TOTAL	**79,470**	**76,126**	**71,794**	**72,526**	**Average**	**11.2**

Percent of total water consumption = 97.1%

NATURAL GAS FIRED PLANTS						Generation Capacity	Ac-ft/MW
Plant Name	2008	2009	2010	2011			
Currant Creek	82	108	82	78		537	0.2
Gadsby	426	680	893	864		351	2.0
Lake Side	1,821	1,287	1,533	1,154		544	2.7
TOTAL	**2,329**	**2,075**	**2,508**	**2,096**		**Average**	**1.6**

Percent of total water consumption = 2.9%

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

Plant Name	2008	2009	2010	2011
Hunter	19,380	19,300	18,941	16,961
Huntington	11,385	10,922	9,549	9,069
Carbon	2,199	2,349	2,193	2,458
Naughton	10,992	10,846	13,354	14,157
Jim Bridger	27,322	25,361	20,757	22,282
TOTAL	**71,278**	**68,778**	**64,794**	**64,927**

Percent of total water consumption = 87.3%

APPENDIX H – WIND INTEGRATION STUDY

This appendix provides the 2012 Wind Integration Study conducted during the 2013 IRP planning process. A draft version of this study was sent to participants in November 2012. The 2012 Wind Integration Study will be presented to the Technical Review Committee for approval in May 2013.

PACIFICORP

2012 WIND INTEGRATION RESOURCE STUDY

APRIL 30, 2013

1. Introduction

The purpose of this study is to estimate the operating reserves required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. The Company must provide sufficient operating reserves to allow the Balancing Authority to meet NERC's control performance criteria (See BAL-007-1[21]) at all times, incremental to contingency reserves which the Company maintains to comply with NERC Standard BAL-002-0[22]. These incremental operating reserves are necessary to maintain area control error[23] within required parameters, apart from disturbance events that are addressed through contingency reserves, due to sources outside direct operator control including intra-hour changes in load demand and wind generation. The study results in an estimate of operating reserve volume and estimated cost of these operating reserves required to manage load and wind generation variation in PacifiCorp's Balancing Authority Areas (BAAs).

The operating reserves contemplated within this study represent regulating margin, which is comprised of ramp reserve extracted directly from operational data, and regulation reserve, which is estimated based on operational data. The study calculates regulating margin demand over two common operational timeframes: ten-minute intervals, called regulating; and one-hour-intervals, called following. The regulating margin requirements are calculated from operational data recorded during PacifiCorp's operations from January 2007 through December 2011 (Study Term). The regulating margin requirements for load variation, and separately for load variation combined with wind variation, are then applied in PacifiCorp's Planning and Risk (PaR) production cost model to isolate the effect additional reserve requirements due to wind generation have on overall system costs. This cost is attributed to the integration of wind generation resources and will change over time with changes in market prices for power and natural gas, changes in PacifiCorp's resource portfolio and potential changes in regional market design, such as an energy imbalance market.

Technical Review Committee

In order to ensure the Company's study is performed according to current best practices and benefits from guidance provided by individuals with diverse wind integration study experience, PacifiCorp used a Technical Review Committee (TRC) for its 2012 Study. The TRC was involved during the Study process, and their recommendations are reflected in the Study method and scenarios addressed. All study results have been presented to and reviewed by the TRC. The members of the TRC are:

- Andrea Coon - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- Randall Falkenberg – President, RFI Consulting, Inc.
- Matt Hunsaker - Manager, Renewable Integration for the Western Electricity Coordinating Council (WECC)
- Michael Milligan - Lead research for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory (NREL)

[21] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf.
[22] NERC Standard BAL-002-0: http://www.nerc.com/files/BAL-002-0.pdf
[23] "Area Control Error" is defined in the NERC glossary here: http://www.nerc.com/files/Glossary_12Feb08.pdf

- J. Charles Smith - Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Robert Zavadil - Executive Vice President of Power Systems Consulting, EnerNex

The study method incorporates improvements resulting from recommendations made by TRC members as well as analyses requested by them. The Company thanks all the TRC members for their reviews of the study method and professional feedback.

1.1 Executive Summary

The 2012 Wind Integration Study (the "Wind Study") estimates the regulating margin requirement from historical load and wind generation production data. The regulating margin is required to manage variations to area control error due to load and wind variations within PacifiCorp's BAAs. The Wind Study estimates the regulating margin requirement based on load combined with wind variation and separately estimates the regulating margin requirement based solely on load variation. The difference between these two calculations, with and without the estimated regulating margin required to manage wind variability and uncertainty, provides the amount of incremental operating reserves required to maintain system reliability due to the presence of wind generation in the PacifiCorp's BAAs. The resulting regulating margin requirement was evaluated deterministically in PaR, a production cost model used in the Company's Integrated Resource Plan (IRP) to evaluate stochastic risk in selection of a preferred resource portfolio, so that the incremental cost of the regulating margin required to manage wind resource variability and uncertainty can be reported on a dollar per megawatt hour (MWh) of wind generation basis.[24]

Table H.1 depicts the combined PacifiCorp BAA annual average regulating margin calculated in this Wind Study, and separates the regulating margin due to load from the regulating margin due to wind.

Table H.1 - Average Annual Regulating Margin Reserves, 2012 Wind Study (MW)

	West BAA	East BAA	Combined
Load-Only Regulating Margin	147	247	394
Incremental Wind Regulating Margin	54	131	185
Total Regulating Margin	202	378	579

Table H.2 depicts the cost to integrate wind generation in PacifiCorp's BAAs. The cost to integrate wind includes the incremental regulating margin reserves to manage intra-hour variances as outlined above and the costs associated with day-ahead forecast variances that affect daily system balancing. Each of these component costs were calculated using PacifiCorp's PaR model. 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 solely with the regulating margin requirement due to load variations, and then again

[24] The PaR model can be run with stochastic variables in Monte Carlo simulation mode or in deterministic mode whereby variables such as natural gas and power prices do not reflect random draws from probability distributions. For purposes of the Wind Study, the intention is not to evaluate stochastic portfolio risk, but to estimate production cost impacts of incremental operating reserves required to manage wind generation on the system based on current projections of future market prices for power and natural gas.

with the increased regulating margin requirements due to load combined with wind generation. The change in system costs between the two PaR simulations results in the wind integration cost.

Table H.2 - Wind Integration Cost (2012$ per MWh of Wind Generation)

Study	2010 Wind Integration Study	2012 Wind Integration Study
Wind Capacity Penetration	2046 MW	2126 MW, 2011 Operational Data
Tenor of Cost	3-year levelized, 2010$	1 year levelized, 2012$
Hourly Reserve ($/MWh)	$8.85	$2.19
Interhour/System Balancing ($/MWh)	$0.86	$0.36
Total Wind Integration ($/MWh)	$9.70	$2.55

The 579 megawatts of regulating margin identified in this study (in Table H.1) is comparable to the 530 megawatts of regulating margin identified in the prior wind integration study developed for the 2011 IRP. While overall operating reserve levels are similar, this Study shows the estimated costs of these operating reserves are lower, and that the reduced cost is primarily driven by declining natural gas and power market prices. Table H.3 compares natural gas and power price assumptions used in the 2010 Wind Integration Study to those used in the 2012 Wind Integration Study.

Table H.3 - Nominal Levelized Natural Gas and Power Prices Used in the 2010 and 2012 Wind Integration Studies

	Palo Verde High Load Hour Power	Palo Verde Low Load Hour Power	Opal Natural Gas
2010 Wind Study	$51.26	$35.60	$5.36
2012 Wind Study	$37.05	$25.74	$3.43

The effect of changing power and natural gas prices on the cost of wind integration is significant, even if the volume of wind being integrated does not change. The value of reserves is often the opportunity cost of a lost sale at a given generation station. This opportunity cost is foregone margin (which is equal to the lost revenue from the wholesale sale) less the variable cost to run the generation plant at a higher level, which is primarily the cost of fuel. Second to hydro generation, natural gas generation is often used to meet the Company's reserve requirements and to manage variability and uncertainty in wind and retail load. This is because gas-fired generation typically has less economic impact when used for reserves than coal-fired generation and has the operational flexibility to ramp up and down as the load and wind fluctuate. As natural gas prices have fallen, the costs of holding reserve capacity have correspondingly dropped even though the quantity of regulating margin requirement has increased.

2. Data

2.1 Overview

The calculation of regulating margin reserve requirement was based entirely on actual historical load and wind production data over the Study Term from January 2007 through December 2011. No simulated wind production data was incorporated in the Wind Study, which is a change from prior studies that did not have the benefit of a more complete historical data set. Table H.4

shows that the ten-minute interval data for wind resources grew substantially during this period as wind resources came online in PacifiCorp's BAAs.

Table H.4 - Historical Wind Production and Load Data Inventory

	Nameplate Capacity	Beginning of Data	End of Data	Location
Wind Plants within PacifiCorp BAAs				
Chevron Wind	17	12/1/2009	12/31/2011	East
Combine Hills	41	1/1/2007	12/31/2011	West
Dunlap I Wind	111	10/1/2010	12/31/2011	East
Foote Creek Generation	85	1/1/2007	12/31/2011	East
Glenrock Wind	99	1/1/2009	12/31/2011	East
Glenrock III Wind	39	1/17/2009	12/31/2011	East
High Plains Wind	99	9/13/2009	12/31/2011	East
Marengo I	140	8/3/2007	12/31/2011	West
Marengo II	70	6/26/2008	12/31/2011	West
McFadden Ridge Wind	29	9/29/2009	12/31/2011	East
Mountain Wind 1 QF	61	7/2/2008	12/31/2011	East
Mountain Wind 2 QF	80	9/29/2008	12/31/2011	East
Oregon Wind Farm QF	65	3/31/2009	12/31/2011	West
Rock River I	50	1/1/2007	12/31/2011	East
Rolling Hills Wind	99	1/17/2009	12/31/2011	East
Seven Mile Wind	99	12/31/2008	12/31/2011	East
Seven Mile II Wind	20	12/31/2008	12/31/2011	East
Spanish Fork Wind 2 QF	19	7/31/2008	12/31/2011	East
Stateline Contracted Generation	150	1/1/2007	12/31/2011	West
Three Buttes Wind	99	12/1/2009	12/31/2011	East
Top of the World Wind	200	10/1/2010	12/31/2011	East
Wolverine Creek	65	1/1/2007	12/31/2011	East
Long Hollow Wind		1/1/2007	12/31/2011	East
Stateline Transmission Customer		1/1/2007	12/31/2011	West
Campbell Wind		12/1/2009	12/31/2011	West
Jolly Hills 1		10/1/2010	12/31/2011	East
Jolly Hills 2		10/1/2010	12/31/2011	East
Wind Plants out of PacifiCorp BAAs				
Goodnoe Hills Wind	94	5/31/2008	12/31/2011	West - out of BAA
Leaning Juniper 1	101	1/1/2007	12/31/2011	West - out of BAA
Load Data				
PACW Load		1/1/2007	12/31/2011	West
PACE Load		1/1/2007	12/31/2011	East

2.2 Historical Load and Load Forecast Data

The historical hourly day-ahead load forecasts and day-ahead hourly wind forecasts used to operate the generation system through the Study Term (2007-2011) were retrieved from Company records. Historical load data for the PacifiCorp East (PACE) and PacifiCorp West (PACW) BAAs were collected for the Study Term from the PacifiCorp PI system[25]. These data

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

were used for all the calculations involving historical load in the Study. The raw load data were reviewed for anomalies prior to further use. Data anomalies can include:

- Incorrect or reversal of sign (recorded data switching from positive to negative)
- Significant and unexplainable changes in load from one ten-minute interval to the next
- Excessive load values

After such review, out of 262,944 ten-minute intervals in the Wind Study, only three ten-minute intervals were identified as representing spurious data; each had extremely high load values that would have been impossible to serve. As depicted in Table H.5, these values were corrected by interpolating the values of the prior and successive ten-minute periods to create a smooth line across the spurious intervals. Since reserves demands are created by sudden, unexpected changes from one period to the next, this correction was intended to mitigate the impacts of spurious data on the calculation of the eventual reserve requirements and costs in this study. No other load data issues were encountered in this study.

Table H.5 - Load Data Anomalies and their Interpolated Solutions

Time	Original	Final	Replacement
8/12/2010 9:10	2,654.20	2,654.20	
8/12/2010 9:20	-288,687,072.00	2,669.24	Average of 9:10 and 9:30
8/12/2010 9:30	2,684.28	2,684.28	
2/3/2011 9:50	3,135.41	3,135.41	
2/3/2011 10:00	409,630.75	3,103.82	9:50 + 1/3 of (10:20 minus 9:50)
2/3/2011 10:10	213,667.91	3,072.23	9:50 + 2/3 of (10:20 minus 9:50)
2/3/2011 10:20	3,040.65	3,040.65	

2.3 Historical Wind Generation and Wind Generation Forecast Data

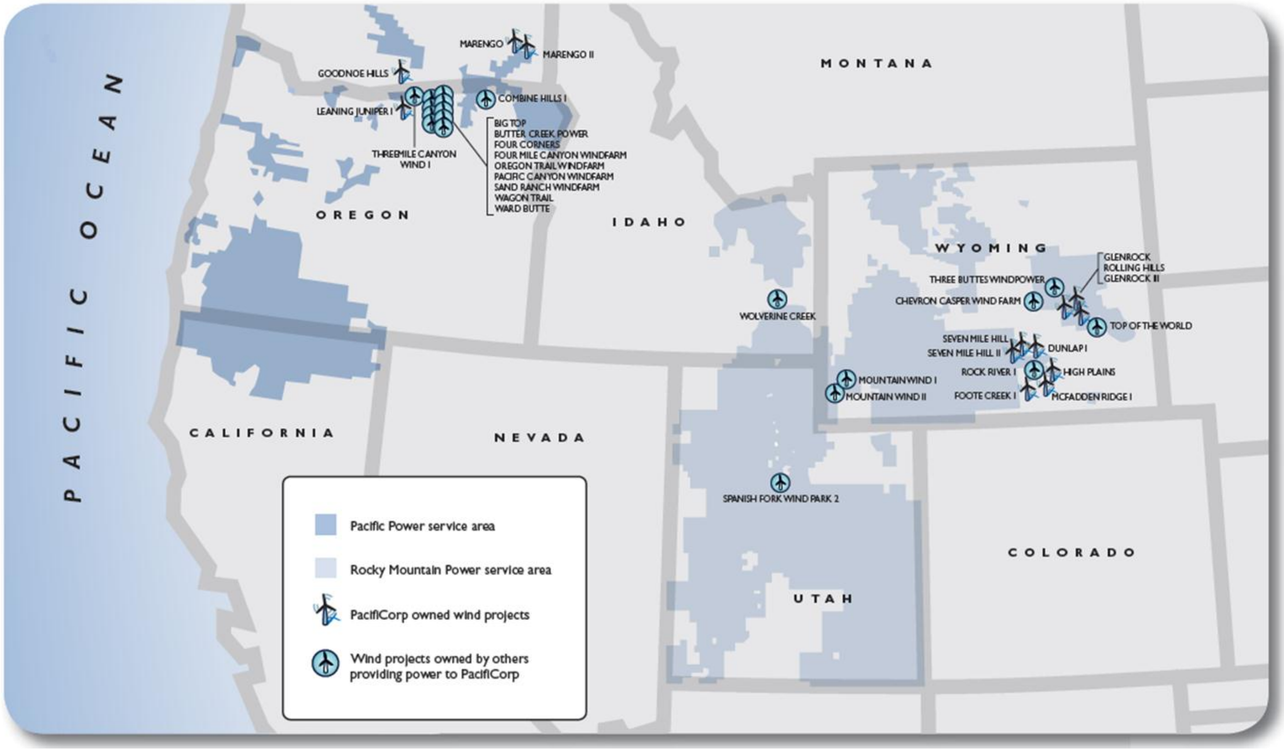
2.3.1 Overview of the Wind Generation Data Used in the Analysis

Over the Study Term, ten-minute interval wind generation data were available for the wind sites as summarized in Table H.4. The wind output data were collected from the PI system. In addition to historical wind generation data, the Wind Study requires historical day-ahead wind forecasts. All of these data sets were needed to establish wind integration costs using the PaR model, and are discussed in turn below.

2.3.2 Historical Wind Generation Data

As shown in Figure H.1, a cluster of PacifiCorp owned and contracted wind generation plants is located in PACW and another cluster is located in PACE. It is worth noting that three wind sites, Wolverine Creek in Idaho, Spanish Fork in Utah, and Mountain Wind in Wyoming, are within PACE, but are geographically distant from both the western and the eastern clusters.

Figure H.1 - Representative Map of PacifiCorp Wind Generating Stations Used in this Study



The wind data collected from the PI system is grouped into a series of sampling points, or nodes, each of which may represent one or more wind plants' output. In consideration of occasional irregularities in the system collecting the data, the raw wind data was reviewed for reasonableness considering the following criteria:

- Incorrect or reversal of sign (recorded data switching from positive to negative)
- Commercial operation date of wind facilities
- Output greater than expected for the wind generation capacity being collected at a given node
- Wind generation appearing constant over a period of days or weeks at a given node

Some PI system data streams exhibit large negative generation output readings in excess of that attributable to station service. These readings reflect positive generation and a reversed polarity on the meter, rather than negative generation or system load. The meter polarity generally remains constant for a long period, and in such instances, the sign was reversed for all data in the period of polarity reversal.

Most of the wind plants in the Wind Study first came online within the Study Period. To reduce one-time impacts due to startup testing or partial facility output as individual wind generators at a given plant were commissioned, wind generation prior to each facility's commercial operation date was not included in the Wind Study.

The PI system ten-minute interval data streams also sometimes exhibit unduly long periods of unchanged or "stuck" values for a given node. Because reserve requirements are driven by large, sudden changes in either wind or load, these data anomalies needed to be addressed. To address these anomalies, the values were held constant when "stuck" values were observed but for the last hour of "stuck" output to smooth the transition to the rest of the data series. For example, if a node's measured wind generation output was 50 megawatts (MW) for three weeks and the first new, fluctuating data value was 75 MW, the value of the last hour of "stuck" data would be replaced with the average of 50 MW and 75 MW. The Company investigated the impact of replacing some of the stuck values with corresponding hourly generation data on the Mountain Wind and Spanish Fork wind plants. As the effect of substituting Mountain Wind and Spanish Fork wind data for some of the stuck values was ascertained to be minimal (less than a tenth of a percent change in the resulting component reserve requirement), the operational data used for the Wind Study was not changed other than the instances described above.[26] In total, the wind generation data adjusted for stuck values represented only 0.5 percent of the wind data used in the Wind Study.

2.3.3 Historical Day-ahead Wind Generation Forecasts

Day-ahead wind forecasts for all owned and contracted wind resources were collected from daily historical records maintained by PacifiCorp commercial operations as well as from the Company's third party wind forecast service provider, Garrad Hassan Co. From year 2007 to year 2009 the same sets of historical day-ahead wind forecast data that were used for the Company's 2010 wind integration study were used again for the 2012 study for consistency. From year 2010 to the end of year 2011, Garrad Hassan provided complete data sets for the historical day-ahead wind forecasts. For transmission customers' resources the Company used the actual hourly wind generation data, eliminating the contribution of day-ahead "forecast error" from these resources, which is consistent with the fact PacifiCorp does not schedule transmission customers' resources located within the Company's BAAs.

During the review process of the 2010 and 2011 data sets, PacifiCorp found the following issues:

- Negative wind generation forecast for a period of consecutive hours
- Wind forecast data shown before the wind resources' official operational dates
- Missing forecast on some hours or on consecutive days

Only one resource had a negative generation forecast, Goodnoe Hills, for the 3-day period 10/3/2011 through 10/6/2011. After confirming the resource was not in station service or maintenance, the sign was corrected and reversed to positive. Any forecast generation before the official commercial operational date was removed from the data series of then newly added resources, consistent with the practice adopted for actual generation as described in the section above.

In the 2010 and 2011 day-ahead forecast data sets, 1.3 percent of the forecast hours were missing data, from one hour up to a week consecutive. If only one hour was missing, that hour forecast was created using the average of the previous hour forecast and the next hour forecast in order to smooth out the fluctuation in the data set. If several days' forecasts were missing, then the latest

[26] By leaving stuck values in place but for the last interval, variability and uncertainty in wind generation from a facility was removed for those intervals in which "stuck" values were observed, which all else equal would result in understating regulation margin requirements.

24 hours of forecast data immediately before the missing days were copied and repeated to fill in the days-long gap. This approach is intended to preserve the smoothness of forecast data while trying not to reduce intermittency in real wind generation forecasts.

3. Method

3.1 Method Overview

This section presents the approach used to establish regulating margin reserve requirements and the method for calculating the associated wind integration costs. Ten-minute interval load and wind data was used to estimate the amount of regulating margin reserves, both up and down, needed to manage variation in load and wind generation within PacifiCorp's BAAs.

3.1.1 Operating Reserves

In order to clarify this requirement, this section discusses the NERC regional reliability standard operating reserve requirement and how it fits into this study. NERC regional reliability standard BAL-STD-002-0[27] requires each Balancing Authority, such as PacifiCorp, to carry sufficient operating reserve at all times. Operating reserve consists of contingency reserve and regulating margin. These reserve requirements necessitate available generation surplus to that required to meet load obligations. Each of these types of operating reserve is further defined below.

Contingency reserve is capacity the Company holds in reserve that can be used to respond to contingency events on the bulk power system (e.g., an instantaneous trip of a large generator). The amount of required contingency reserve is defined in NERC BAL-STD-002-0. Contingency reserve may not be applied to manage other system fluctuations such as changes in load or wind generation output. Therefore, this study focuses on the operating reserve component to manage load and wind generation variations, which is incremental to contingency reserve, and also referred to in NERC BAL-STD-002-0 as regulating margin.

Regulating margin is the additional capacity the Company holds in reserve to ensure it has adequate reserve at all times to meet the NERC Control Performance Criteria in BAL-007-1[28]. NERC Control Performance Criteria require the Company to carry regulating reserves incremental to contingency reserves to maintain reliability. However, these additional regulating reserves are not defined by a simple formula, but rather are the amount of reserves required by each BA to meet the control performance standards. Since the Company's 2010 Wind Integration Study[29], the performance standards have evolved from a calculated Control Performance Standard 2 (CPS2)[30] mandated by NERC BAL-001-0[31] to a more dynamic regime mandated by

[27] http://www.nerc.com/files/BAL-STD-002-0.pdf
[28] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf. According to WECC Operating Committee meeting highlights (page 4, item 5), the field trial of this standard has been extended an additional year. The highlights are published here: http://www.wecc.biz/committees/StandingCommittees/OC/20130108/Lists/Agendas/1/OC%20Voting%20Record%20January%202013_Final_Revised.pdf
[29] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, page 11
[30] PacifiCorp has not controlled to CPS2 since March 1, 2010.
[31] http://www.nerc.com/files/BAL-001-0_1a.pdf

NERC BAL-007-1, called Balancing Authority ACE Limit (BAAL), in which the Company's performance standard can be affected by the frequency of the interconnection. This new standard allows a greater ACE during periods when the ACE is helping frequency. However, the Company cannot plan on knowing when ACE will help or exacerbate frequency so the L_{10} is used for the bandwidth in both directions of the ACE. Thus the Company determines, based on the unique level of wind and load variation in its system, and the prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and wind changes throughout the delivery hour. PacifiCorp further segregates regulating margin into two components to assist in the analysis: ramp reserve and regulation reserve.

Ramp Reserve: Due to a number of factors (fluctuations in customer demand, spot transactions, varying amounts of generation produced by variable resources such as wind and solar generation) the net balancing area load changes from minute-to-minute, hour-to-hour continuously at all times. This variability (increasing and decreasing load) requires ready capacity to follow continuously, through short deviations, at all times. Treating this variability as though it is perfectly known for future time intervals (as though the operator would know exactly what the net balancing area load would be a minute from now, ten minutes from now, and an hour from now) defines the ramp of the system.

Regulation Reserve: Changes in load or wind generation are not considered contingency events, yet these events still require that capacity be set aside. The Company has defined two types of regulation reserve – regulating and following reserves. Regulating reserve covers short term variations (seconds to minutes, normally using automatic generation control) in system load and wind, whereas following reserve covers uncertainty across an hour normally using manual generation control.

To summarize, regulating margin represents operating reserves the Company holds over and above the mandated contingency reserve requirement to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts; ramp reserve and regulation reserve. The ramp reserve represents a minimum amount of flexibility required to follow the actual net system load (load minus wind generation output) with dispatchable generation. The regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors about the net system load, and consists of four components: load following, load regulating, wind following, and wind regulating.

3.1.2 Method Steps

The regulating margin requirements are calculated for each of the Company's BAAs from production data via a five step process, each described in more detail later in this section. The five steps include:

1. Calculation of the ramp reserve from the historical data (with and without wind generation).
2. Creation of hypothetical forecasts from historical load and wind production data.
3. Compare actual generation and load values in each ten-minute interval of the study term to the hypothetical forecast values, and record the differences as deviations.
4. Group these deviations into bins that can be analyzed for the reserves requirements per forecast value of wind and load, respectively, such that a specified percentage (or

tolerance level) of these deviations would be covered by some level operating reserves.

5. Apply the reserve requirements noted for the various wind and load forecast values are then applied back to the operational data, enabling an average reserves requirement to be calculated for any chosen time interval within the Study Term.

Once the amount of regulating margin is estimated, the cost of holding the specified reserves on PacifiCorp's system is estimated using the PaR model. In addition to using PaR for evaluating operating reserve cost, the PaR model is also 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 as they occur in real time.

3.2 Regulating Margin Requirements

As noted above, ten-minute interval wind generation and load data drives the calculation of the regulating margin requirement for ramp reserve and regulation reserve. The approach for calculating regulating margin requirements necessary to supply adequate operational capacity is based on merging current operational practice with a survey of papers on wind integration[32] and input from the TRC.

3.2.1 Ramp Reserve

The ramp reserve represents the minimal amount of flexible system capacity required to follow the net load requirements without any error or deviation; in other words, if a system operator had the gift of perfect foresight for following changes in load and wind generation from minute-to-minute, and hour-to-hour. These amounts are as follows:

- If system is ramping down: [(Net Area Load Hour H – Net Area Load Hour (H+1))/2]
- If system is ramping up: [(Net Area Load Hour (H+1)– Net Area Load Hour H)/2]

Essentially, the ramp reserve is half the absolute value of the difference between the net balancing area load at the top of one hour minus the net balancing load at the top of the prior hour.

The ramp reserve is calculated for load using only the load values for each BAA at the top of each hour. The ramp reserve for load and wind is calculated using the net load (load minus wind generation output) at the top of each hour. The ramp reserve required for wind is the difference between that for load and that for load and wind.

3.2.2 Regulation Reserve

As ramp reserves represent the system flexibility required to follow the system's requirements without any uncertainty or error, the regulation reserve is necessary to cover uncertainty ever-present in power system operations. Very short-term fluctuations in weather, load patterns, wind generation output and other system conditions cause short term forecasts to change at all times.

[32] Many of the external studies PacifiCorp has relied on can be found on the Utility Variable Integration Group (UVIG) website at the following link: http://www.uwig.org/opimpactsdocs.html

Therefore, system operators rely on regulation reserve to allow for the unpredictable changes bound to occur between the time the next hour's schedule is made and the arrival of the next hour, or the ability to follow net load. Also, these very same sources of instability are active throughout each hour, requiring flexibility to regulate the generation output to the myriad ups and downs of customer demand, fluctuations in wind generation, and other system disturbances. To assess the regulation reserve requirements for PacifiCorp's BAAs, the Company compared the operational data to hypothetical forecasts as described below.

3.2.3 Hypothetical Operational Forecasts

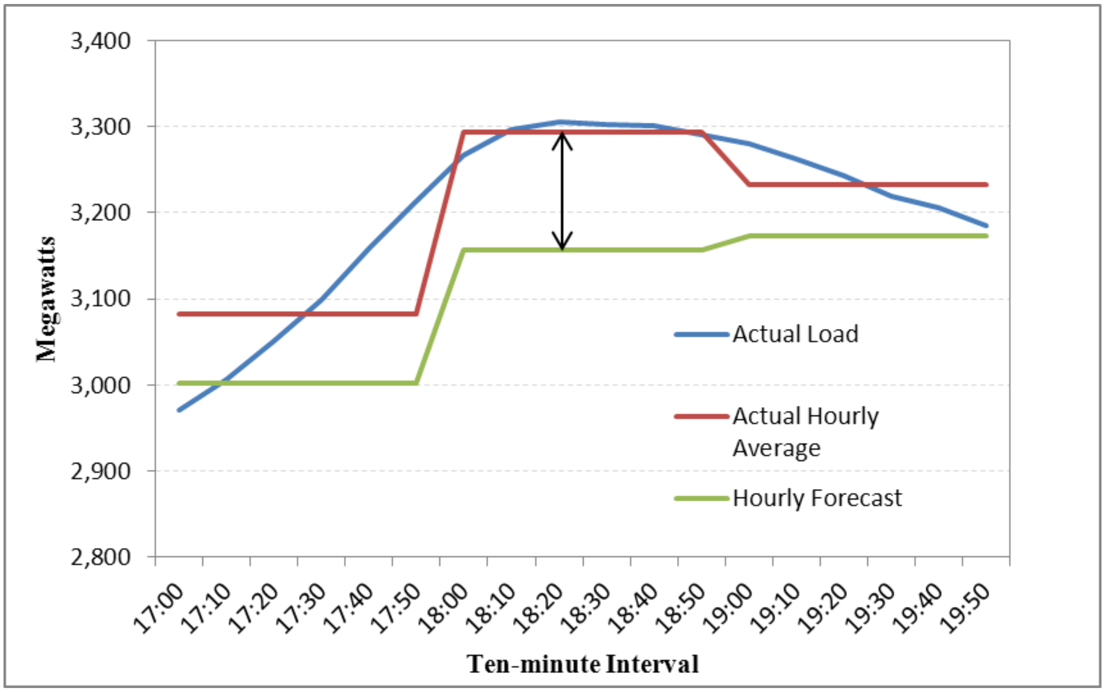
Regulation reserve consists of two components: (1) regulating, which is developed using the ten-minute interval data, and (2) following, which is calculated using the same data but estimated on an hourly basis. The Study Term load data and wind generation data are applied individually to calculate estimated reserve requirements for each month in the Study Term. For purposes of the Study, the regulating calculation compares observed ten-minute interval load and wind generation production to a ten-minute interval forecast, and following compares observed hourly averages to an average hourly forecast. Therefore, the calculation of regulation reserve requirements begins with the development of four component requirements: load following, wind following, load regulating, and wind regulating.

3.2.3.1 Hypothetical Load Following Operational Forecast

PacifiCorp maintains system balance by optimizing its operations to an hourly forecast every hour with changes in generation and market activity. This planning interval represents hourly changes in generation that are assessed roughly 20 minutes into each hour to account for a bottom-of-the-hour (30 minutes after the hour) 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 load (net of wind generation) may be.

PacifiCorp's real-time desk updates the next hour's 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 difference or "delta") is 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 real-time desk 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 same hours that occurred from the prior Monday's was 5 percent, the operator will use a 5 percent change in load as the next hour's following forecast. For purposes of the calculation made in this Wind Study, 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. The differences observed between hourly average load and the load following forecasts comprise the load following deviations. Figure H.2 shows an illustrative example of a load following deviation using operational data from PACW, depicted by the black arrow.

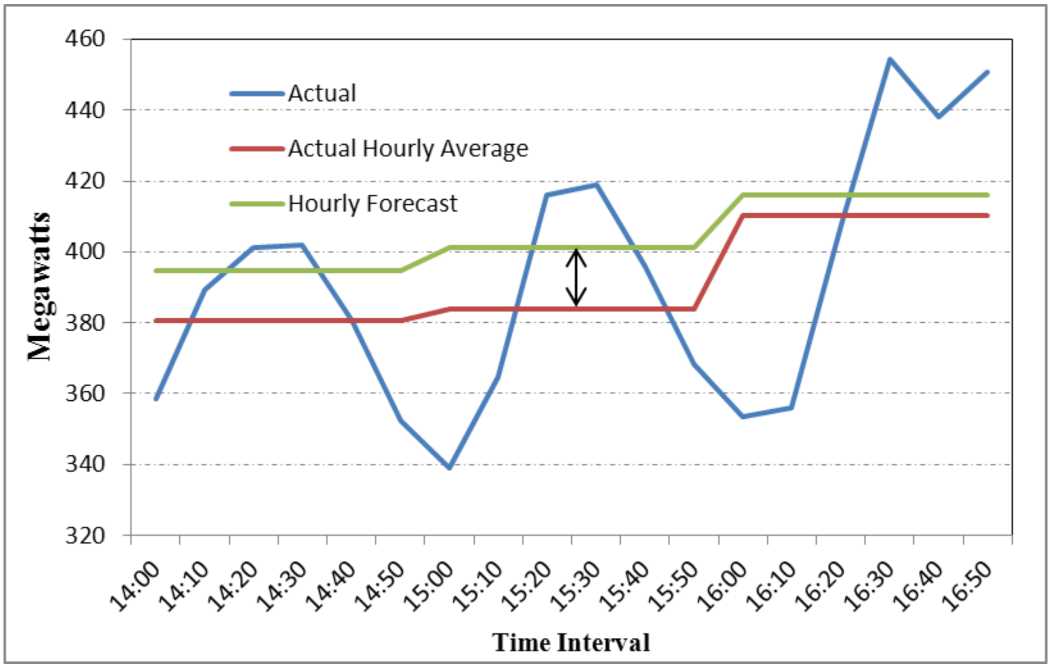
Figure H.2 - Illustrative Load Following Forecast and Deviation



3.2.3.2 Hypothetical Wind Following Operational Forecast

For the corresponding short term hourly operational wind forecast, the hourly wind forecast is prepared based on the concept of 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. For purposes of the calculation made in this study, the hourly wind forecast consisted of the 20th minute output from the prior hour, and this output is assumed to be the volume of wind produced in the ensuing hour. For example, if the wind generation is producing 200 MW of power at 1:20pm in PACW, then it is assumed that 200 megawatt-hour (MWh) of power will be generated from the wind plants between 2:00pm and 3:00pm that day. The difference observed between hourly average wind generation and the wind following forecast represents the wind following deviation. Figure H.3 shows an illustrative example of a wind following deviation using operational data from PACW, depicted by the black arrow.

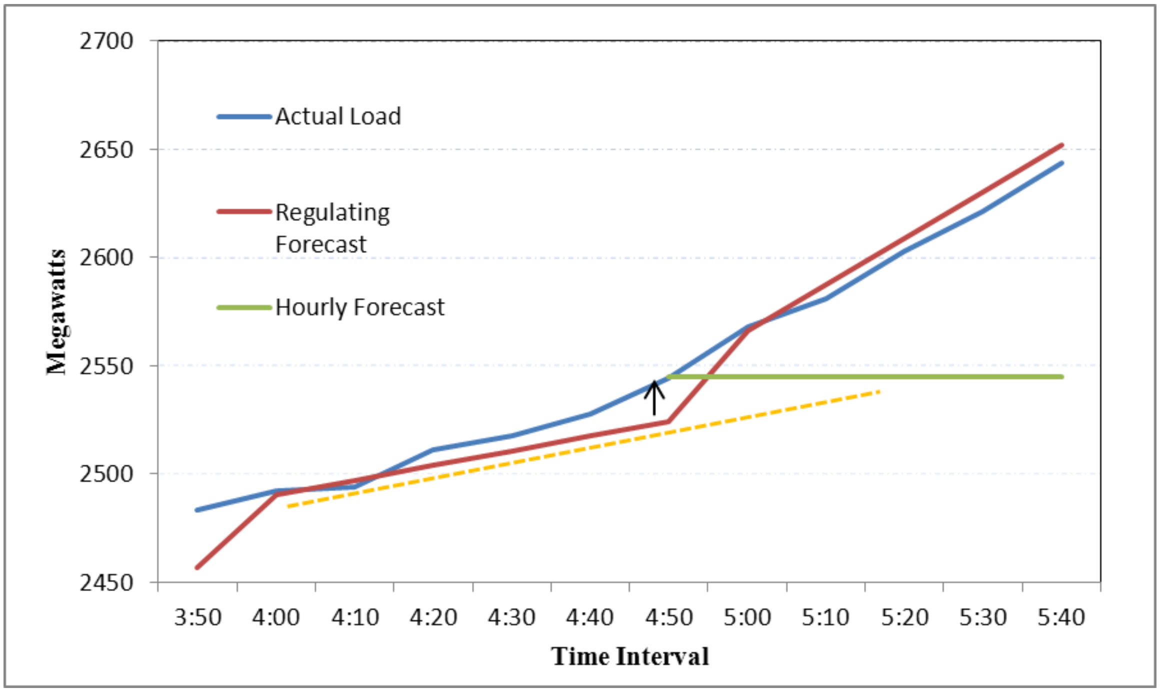
Figure H.3 - Illustrative Wind Following Forecast and Deviation



3.2.3.3 Hypothetical Load Regulating Operational Forecast

Separate from the variations in the hourly scheduled loads, the ten-minute load variability and uncertainty was analyzed by 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 H.4, with the trend of the line of intended schedule tracking the orange line toward the load following forecast at the middle of the ensuing hour as based upon data from PACW from December 2010. The method approximates the 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 actual ten-minute load values were compared to this straight line to produce a corresponding strip of load regulating deviations at each ten-minute interval, with one such deviation represented by the black arrow in Figure H.4.

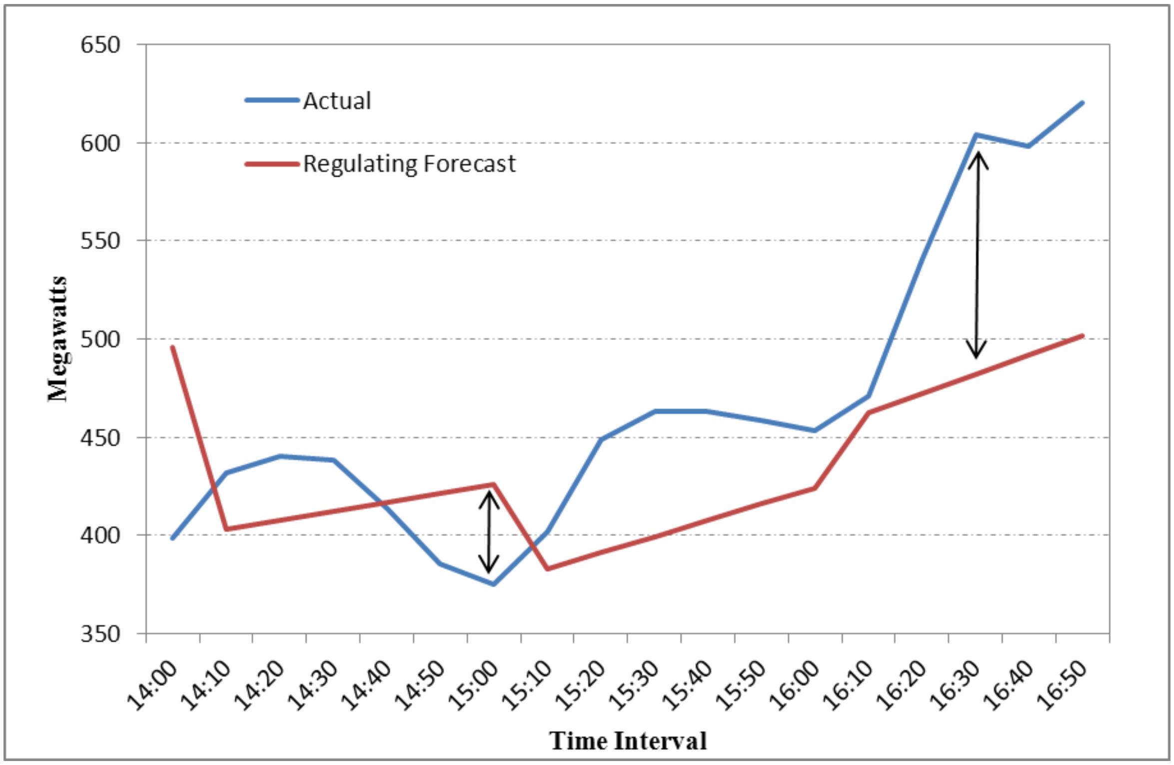
Figure H.4 - Illustrative Load Regulating Forecast and Deviation



3.2.3.4 Hypothetical Wind Regulating Operational Forecast

To parse the ten-minute interval wind variability from the following analysis, a line of intended schedule similar to that applied to load regulating deviations is developed. A line is drawn from the top of the hour's instantaneous wind output to the next hour's wind-following forecast output, but at the bottom (middle) of that next hour. This creates a line from the top of the hour actual output toward the next hour's average output. Figure H.5 shows an illustrative example using operational data from PACW of a wind regulation deviation, as depicted by the black arrow.

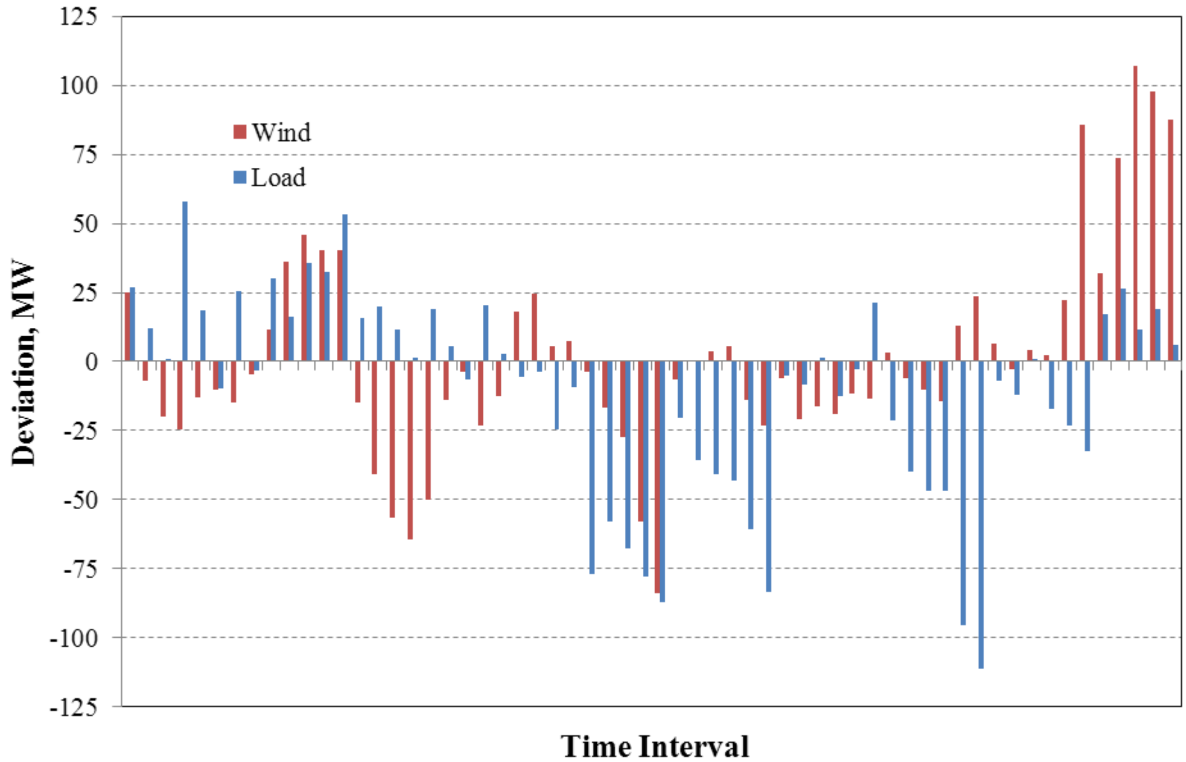
Figure H.5 - Illustrative Wind Regulating Forecast and Deviation



3.2.4 Recording of Deviations

The four hypothetical operational forecasts are netted against historical load and wind production data to derive four component forecast deviations (load following, wind following, load regulating, wind regulating). The deviations each represent different components (like vectors) of forecast error which have to be covered by operating reserves. For example, if the difference between the wind following forecast for a given hour is 550 MW, and the average wind generation on the system only produces 400 MW for that hour, then 150 average MW will have to be produced by other generation on the system to remedy the shortfall and maintain system balance. This is an example of reserves being deployed upward (additional generation dispatched) in real time. A similar effect happens when load exceeds the load forecast – additional generation is dispatched to cover the shortfall due to changing forecasts or unpredictable conditions. Figure H.6 shows an illustrative example of independent load and wind regulating deviations from the PACE on June 1, 2011. Each time interval as represented on the horizontal axis represents ten minutes. Note how the deviations are randomly constructive (both positive or both negative) or destructive (opposing, one positive and one negative).

Figure H.6 - Illustrative Example of Independent Load and Wind Regulating Deviations



The deviations are calculated for each ten-minute interval in the Study Term, for each of the four components of regulation reserves (load following, wind following, load regulating, wind regulating). Across any given hourly time interval, the six ten-minute intervals within each hour would have a common following deviation, but different regulation deviations. For example, considering load deviations only, if the load forecast for a given hour was 300 MW below the actual load realized in that hour, then a load following deviation of -300 MW would be recorded for all six of the ten-minute periods within that hour. However, as the load regulation forecast and the actual load recorded in each ten-minute interval vary, so will the deviations for load regulation. The same trend holds for wind following and wind regulating deviations. The following deviation is recorded as equal for the hour, and the regulating deviation varies each ten-minute interval.

3.2.5 Analysis of Deviations

Since the recorded deviations represent the amount of unpredictable variation on the electrical system, the key question becomes how much regulation reserve to hold in order to cover the deviations, thereby maintaining system reliability. The deviations are analyzed by separating the deviations into bins by their characteristic forecasts for each month in the Study Term. The bins are defined by every 5th percentile of recorded forecasts, creating 20 bins for each month's deviations for each component hypothetical operational forecast. In other words, each month of the Study Term will exhibit 20 bins of load following deviations, 20 of load regulating deviations, and the same for wind following and wind regulating. Tables H.6 and H.7 depict this process in action for June 2011.

Table H.6 depicts the calculation of percentiles (every 5 percent) among the load regulating forecasts for June 2011 using PACE operational data. For example, a load regulating forecast of

4,403.7 MW represents the fifth percentile of such forecasts for that month. Any forecast values below that value will be in Bin 20, along with the respective deviations recorded for those time intervals. Any forecast values between 4,403.7 MW and 4,508.8 MW will land the deviation for that particular interval in Bin 19.

Table H.6 - Percentiles Dividing the June 2011 Load Regulating Forecasts into 20 Bins

East		
Bin Number	Percentile	Load Forecast
	MAX	7,615.4
1	0.95	6,916.8
2	0.90	6,549.0
3	0.85	6,210.6
4	0.80	5,984.1
5	0.75	5,803.9
6	0.70	5,685.5
7	0.65	5,599.5
8	0.60	5,523.1
9	0.55	5,445.0
10	0.50	5,356.4
11	0.45	5,267.4
12	0.40	5,160.0
13	0.35	5,037.1
14	0.30	4,924.5
15	0.25	4,812.5
16	0.20	4,683.5
17	0.15	4,570.0
18	0.10	4,447.5
19	0.05	4,359.9
20	MIN	4,107.2

Table H.7 depicts a sample of the assignment of several intervals' data into bins following the definition of bins in Table H.6.

Table H.7 - Recorded Interval Load Regulating Forecasts and their Respective Errors, or Deviations, for June 2011 Operational Data from PACE

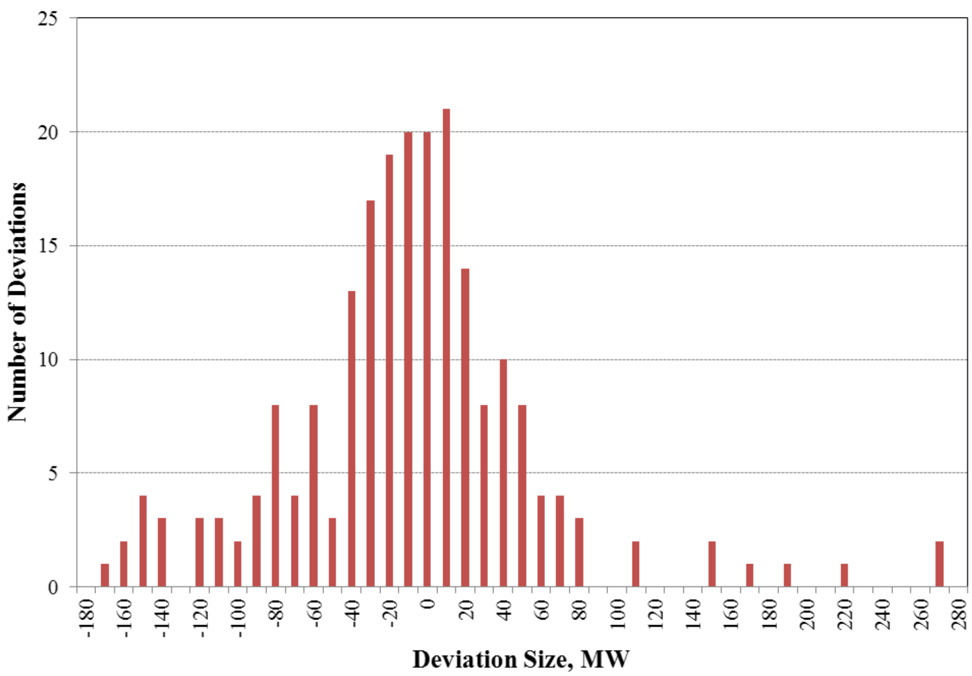
EAST			
DATE / TIME	LOAD REGULATION FORECAST	LOAD REGULATION ERROR	BIN ASSIGNMENT
06/01/2011 01:00	4,297.0	26.89	20
06/01/2011 01:10	4,277.7	12.17	20
06/01/2011 01:20	4,285.3	0.76	20
06/01/2011 01:30	4,292.9	57.93	20
06/01/2011 01:40	4,300.4	18.72	20
06/01/2011 01:50	4,308.0	-9.78	20
06/01/2011 02:00	4,315.6	25.25	20
06/01/2011 02:10	4,315.9	-3.19	20
06/01/2011 02:20	4,341.4	29.87	20
06/01/2011 02:30	4,366.9	16.33	19
06/01/2011 02:40	4,392.4	35.67	19
06/01/2011 02:50	4,417.9	32.28	19
06/01/2011 03:00	4,443.5	53.28	19
06/01/2011 03:10	4,429.4	15.66	19
06/01/2011 03:20	4,468.6	20.02	18
06/01/2011 03:30	4,507.8	11.52	18
06/01/2011 03:40	4,547.0	1.15	18
06/01/2011 03:50	4,586.2	18.98	17
06/01/2011 04:00	4,625.4	5.76	17
06/01/2011 04:10	4,658.2	-6.29	17
06/01/2011 04:20	4,696.8	20.29	16
06/01/2011 04:30	4,735.3	2.56	16
06/01/2011 04:40	4,773.9	-5.57	16
06/01/2011 04:50	4,812.5	-3.52	16
06/01/2011 05:00	4,851.0	-24.55	15
06/01/2011 05:10	4,905.0	-9.43	15

The binned approach is necessary to prevent over-assignment of reserves in different system states, owing to certain characteristics of load and wind generation. For example, when the balancing area load is near the lowest values for any particular day, it is highly unlikely the load deviation will require substantial down reserves to maintain balance because load will typically drop only so far. Similarly, when the load is near the peak of the month’s load values, it is likely perhaps to go only a little higher, but could drop substantially at any time. Similarly for wind, when wind generation output is at the peak value for a system, there will not be a deviation taking the wind value above that peak. In other words, the directional nature of the reserves requirements can change greatly by the state of the load or wind output. At high load or wind generation states, there is not likely to be a significant need for reserves covering a surprise increase in those values. Similarly, at the lowest states, there is not likely to be a need for the direction of reserves covering a significant shortfall in load or wind generation.

For example, consider the deviations grouped into one of the load regulating bins for June 2011 data in Figure H.7. The deviations in this bin all occurred in time intervals with a load regulating forecast near 6,898 MW, from the PACE using June 2011 operational data. Most of the deviations are within 80 MW of the actual load value (a little over one percent, plus or minus).

However, for load regulating deviations in this range, there is apparently a greater tendency where actual load was lower (more negative deviations than positive in Figure H.7 below, and of greater magnitude), which requires the system's installed generation to have to increase its output in a very short timeframe to balance, thus requiring what are called "up reserves". It also bears noting that the deviations form a statistical distribution which is not normally shaped; and as more bins are examined, they also are not normally distributed and the longer tail can appear on either side.

Figure H.7 - Histogram of Deviations Occurring About a June 2011 PACE Load Regulating Forecast of 6,097 MW



Bin Analysis

Up and down deviations must be served by operating reserves, so the percentile equivalent to a deviation tolerance was sampled above and below the median of each of the bins. The difference between the target reliability percentiles and the median of the bins represents the implied incremental load following service for regulation reserve demand within that bin for a given tolerance level. The component reserve value for each bin, as a function of the tolerance target is represented in Equation 1:

Equation 1. Derivation of the component reserves requirement as a function of deviations recorded in each bin.

$$\textbf{Component Reserve}_j = \mathbf{f}(\mathbf{P}_{tolerance}(\textbf{Forecast Bin}_i))$$

Where:

$\mathbf{P}_{\mathbf{tolerance}}$ = The percentile of a two-tailed distribution representing an operational tolerance target

Forecast Bin$_i$ = the component forecast errors in each bin

The tolerance level, per Equation 1, represents a percentage of component deviations intended to be covered by the associated component reserve. As detailed in the method overview, section 3.1, the Company cannot apply contingency reserves to manage load and wind fluctuations, and therefore must carry sufficient regulating margin to avoid dipping into contingency reserve for this purpose. Any failure to manage these fluctuations can lead to disruption of services to customers. Surveying other recent wind integration studies[33], the company focused on two other large regional entities grappling with the same concerns; BC Hydro and Bonneville Power Administration ("BPA"). BC Hydro applies a 99.7 percent tolerance to respective load and wind reserve requirements[34], while the BPA customarily applies a 99.5 percent tolerance to its balancing requirements[35]. Considering the actions of other major market participants, and the requirement to maintain contingency reserves at all times, the Company has decided to apply a 99.7 percent tolerance in the calculation of component reserves, In doing so, the Company has sought to plan for as many deviations as possible, while excluding the very largest data points to allow for the potential existence of outlier values. However, in a departure from BC Hydro's and BPA's approaches, the Company will also net the appropriate system L_{10} from the resulting total reserves requirement[36], effectively reducing the target reserve requirement to a more aggressive level than those other market participants. The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails. Despite exclusion of extreme deviations with the use of the 99.7 percent tolerance, the Company's system operators will still be expected to meet reserve requirements without exceptions. The Company may also change the tolerance based on operational and customer feedback in the future.

Taking the binned data illustrated in Figure H.7 as an example, approximately all of the deviations fall between -180 MW of deviation and +270 MW of deviation. Therefore, at a 99.7 percent tolerance level, the load regulating up reserves recommended for time intervals reflecting a load regulating forecast near 6,097 MW in the PACE in June 2011 is 173 MW. As each respective bin also has an implied probability by the number of data points falling within it (five percent), five percent of the ten-minute intervals in June 2011 will be assigned a load regulating component reserves value of 210 MW up reserves and 130 MW down reserves. The very same analysis is performed for each bin (20 in total) for wind regulating, load following, and wind following component reserves.

The binned results can be reviewed for a month at a time, and patterns in the up- and down-reserves requirements by forecast level become more apparent for load and for wind as shown in Figures H.8 and H.9. For example, Figure H.9 can be used to further explain the calculation

[33] PacifiCorp reviewed wind integration studies sponsored by other regional utilities (Portland General Electric, Avista, Idaho Power, BC Hydro, BPA) and the National Renewable Electrical Laboratory. The more recent BC Hydro and BPA approaches are consistent with the Company's requirement to maintain contingency reserve requirements at all times.

[34] BC Hydro's Wind Integration Study is part of its Integrated Resource Plan, Appendix 6E, page 6E-9: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf

[35] Pacific Northwest National Laboratory, page 5: http://energyenvironment.pnnl.gov/ei/pdf/NWPP%20report.pdf

[36] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to: http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf

method for the resulting component reserve demand. Bin 4 describes 36 hours (five percent of June's 720 hours) of wind generation forecast outcomes in the operational data from June, 2011. The average hypothetical operational forecast modeled for these hours was 710 MW of production, and 99.7 percent of the actual hourly production values would be between 305 MW (the bottom of the green shaded area) and 955 MW (the top of the red shaded area). Therefore, for these 36 hours, and other periods in the future where the PACE wind production forecast is near 710 MW, this method recommends 405 MW of up reserves (710 – 305 = 405) in order to be prepared for a shortfall in wind production compared to the hourly forecast.

Figure H.8 - Load Following Component Reserve Profile; Operational Data from June 2011

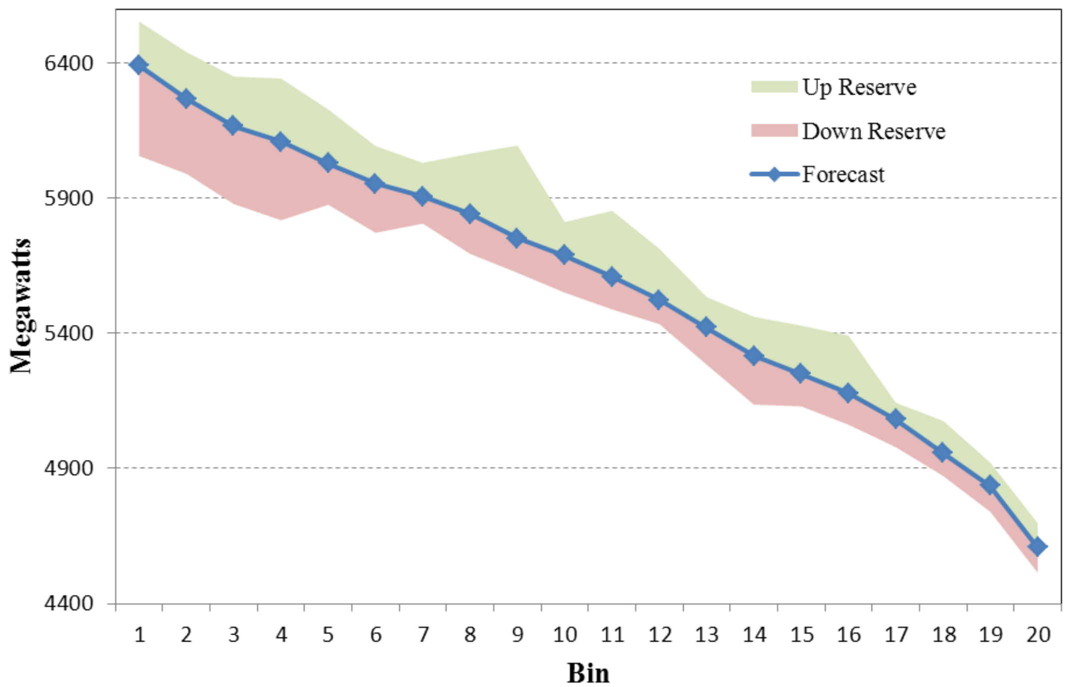
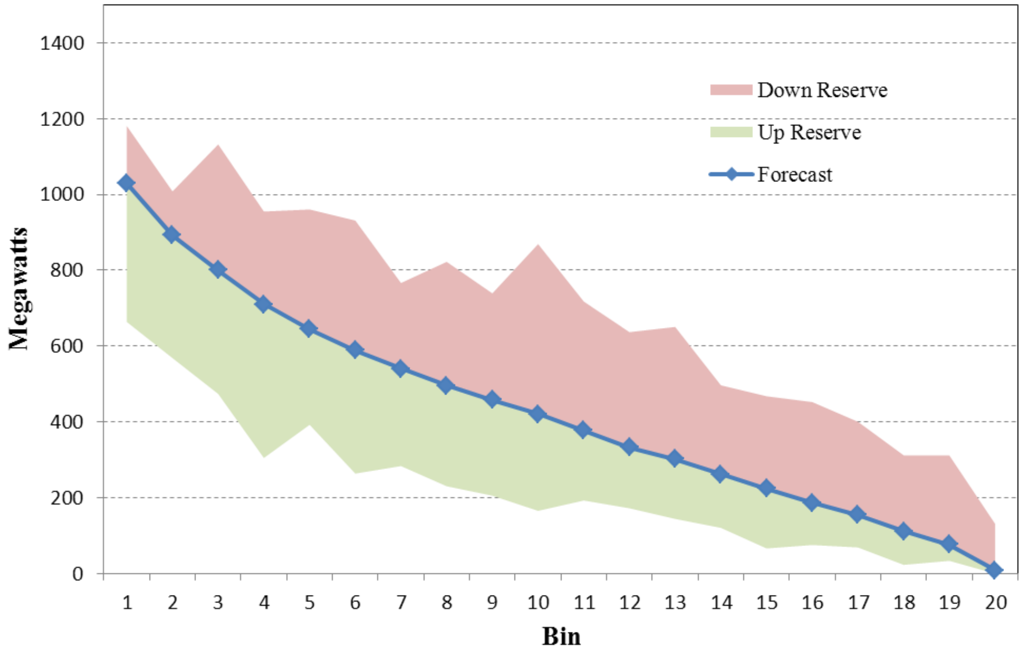


Figure H.9 - Wind Following Component Reserve Profile; Operational Data from June 2011



It is also useful to note the relatively small amount of up reserve required when the wind generation is forecast to be low (Bins 19 and 20), and vice-versa when little wind generation is forecast (Bins 1 and 2 in Figure H.9). This is how the bin analysis helps prevent over-assigning reserves—by adjusting the reserves requirements per wind generation state. For instance, the output of wind generators is less stable when the wind is picking up or slowing down, and the wind generators are speeding up or slowing down accordingly. This behavior is represented in Bins 3 through 15 in Figure H.9 above; the amount of wind following component reserve recommended in those bins (represented by the distance between the red forecast line and the blue and green lines) is greater than that needed at the higher and lower rates of production, which represent either sustained wind or sustained calmer conditions.

The result of the bin analysis is four component forecast values (load following, wind following, load regulating, wind regulating) for each ten-minute interval of the Study Period. The component forecasts and reserves requirements are then applied to the operational data and combined in the backcasting procedure described below.

3.2.6 Backcasting

Given the development of component reserves demands for regulating and following timeframes shaped to system state in section 3.2.5, reserve requirements were then assigned to each ten-minute interval in the Study term according to their respective hypothetical operational forecasts (created in the Wind Study's prior steps) to simulate the combination of the component reserves values as they would have happened in real-time operations. Doing so results in a total reserves requirement for each interval informed by the data.

To perform the backcasts, the component reserves requirements calculated from the bin analysis described above are first turned into reference tables. Table H.8 shows a sample (June 2011, PACE) reference tables for load and wind following reserves at varying levels of forecasted load and wind generation. Table H.9 shows a sample (June 2011, PACE) reference table for load and wind regulating reserves at varying forecast levels.

Table H.8 - Sample Reference Table for Load and Wind Following Component Reserves

	East			East		
Bin	Up	Load Forecast	Down	Up	Wind Forecast	Down
	163	10000	335	365	5000	151
1	163	6953	335	365	1029	151
2	172	6544	278	324	893	115
3	182	6240	289	327	801	331
4	233	5954	291	405	710	245
5	199	5802	153	252	645	316
6	138	5699	182	325	589	342
7	126	5601	99	256	540	227
8	223	5526	147	265	495	327
9	**345**	**5432**	**126**	**253**	**459**	**281**
10	123	5362	138	255	420	449
11	245	5260	120	184	377	340
12	189	5151	89	161	333	304
13	113	5033	137	158	302	348
14	145	4931	180	141	262	235
15	179	4809	120	158	224	243
16	213	4694	117	111	187	266
17	62	4551	102	86	155	246
18	119	4437	85	89	112	200
19	85	4338	97	44	77	234
20	90	4098	94	44	9	122
	90	0	94	44	0	122

Table H.9 - Sample Reference Table for Load and Wind Regulating Component Reserves

	East			East		
Bin	Up	Load Forecast	Down	Up	Wind Forecast	Down
	171	10000	263	244	10000	152
1	171	6917	263	244	1025	152
2	183	6549	251	302	902	224
3	177	6211	163	353	794	237
4	173	5984	272	224	713	180
5	204	5804	130	317	649	270
6	155	5686	156	263	585	450
7	219	5600	114	202	539	352
8	239	5523	146	260	501	394
9	**159**	**5445**	**134**	270	461	244
10	235	5356	124	**190**	**425**	**299**
11	170	5267	115	182	378	251
12	170	5160	112	149	334	265
13	239	5037	151	153	299	260
14	116	4925	138	148	261	172
15	126	4812	162	86	224	288
16	161	4683	103	122	188	287
17	98	4570	113	105	149	174
18	97	4448	95	60	112	144
19	82	4360	101	38	76	150
20	72	4107	92	39	10	82
	72	0	92	39	0	82

Each of the relationships recorded in the table is then applied to hypothetical operational forecasts. Building on the reference tables above, the hypothetical operational forecasts described in sections 3.2.3.1 through 3.2.3.4 are then used to calculate a reserves requirement for each interval of historical operational data. This is clarified in the example below.

Application to component forecasts
Each interval's component forecasts are used, in conjunction with Tables H.8 and H.9, to derive a recommended reserve requirement informed by the load and wind generation conditions for the time interval. This process is most easily explained with an example using the tables shown above, and hypothetical operational forecasts from June 2011 operational data for PACE. Table H.10 illustrates the outcome of the process for the load following and regulating components:

Table H.10 - Interval Load Forecasts and Component Reserves Requirement Data for Hour-ending 11 AM, June 1, 2011 in PACE

East	East	East	East	East	East	East	East	East
Time	Actual Load (10-min Avg)	Actual Load (Hourly Avg)	Following Forecast Load:	Load Following Up Reserves Specified by Tolerance Level	Load Following Down Reserves Specified by Tolerance Level	Regulating Load Forecast:	Load Regulating Up Reserves Specified by Tolerance Level:	Load Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	5,533.04	5,543.46	5,509.68	344.8	126.2	5500.6	159.4	134.4
06/01/2011 10:10	5,525.38	5,543.46	5,509.68	344.8	126.2	5542.6	239.4	145.5
06/01/2011 10:20	5,525.54	5,543.46	5,509.68	344.8	126.2	5552.1	239.4	145.5
06/01/2011 10:30	5,550.23	5,543.46	5,509.68	344.8	126.2	5561.6	239.4	145.5
06/01/2011 10:40	5,551.93	5,543.46	5,509.68	344.8	126.2	5571.1	239.4	145.5
06/01/2011 10:50	5,574.64	5,543.46	5,509.68	344.8	126.2	5580.7	239.4	145.5

The load following forecast for this particular hour is 5,509.68 MW, which designates reserves requirements from Bin 9 as depicted (with shading for emphasis) in Table H.8. Note the same following forecast is applied to each interval in the hour for the purpose of developing reserves requirements. The first ten minutes of the hour exhibits a load regulating forecast of 5,500.6 MW, which designates reserves requirements from Bin 9 as depicted in Table H.9. Note that the regulating forecast changes every ten minutes, and as a result, the regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast shifts the component reserves requirement from Bin 9 to Bin 8 (per Table H.8), and so the component reserves requirement changes accordingly. A similar process is followed for wind reserves, illustrated in Table H.11:

Table H.11 - Interval Wind Forecasts and Component Reserves Requirement Data for Hour-ending 11 AM June 1, 2011 in PACE

East	East	East	East	East	East	East	East	East
Time	Actual Wind (10-min Avg)	Actual Wind (Hourly Avg)	Following Forecast Wind:	Wind Follow Up Reserves Specified by Tolerance Level	Wind Follow Down Reserves Specified by Tolerance Level	East Wind Regulating Forecast:	Wind Regulating Up Reserves Specified by Tolerance Level:	Wind Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	550.82	555.26	485.02	252.87	280.56	453.5	190.0	298.9
06/01/2011 10:10	557.30	555.26	485.02	252.87	280.56	548.5	201.5	352.2
06/01/2011 10:20	529.71	555.26	485.02	252.87	280.56	546.1	201.5	352.2
06/01/2011 10:30	550.40	555.26	485.02	252.87	280.56	543.8	201.5	352.2
06/01/2011 10:40	560.53	555.26	485.02	252.87	280.56	541.4	201.5	352.2
06/01/2011 10:50	582.79	555.26	485.02	252.87	280.56	539.1	259.7	394.0

The wind following forecast for this particular hour is 485.0 MW, which designates reserves requirements from Bin 9 under wind forecasts as depicted in Table H.8. Note the following forecast is applied to each interval in the hour for the same of developing reserves requirements. Meanwhile, the regulating forecast changes every ten minutes. The first ten minutes of the hour exhibits a wind regulating forecast of 453.5 MW, which designates reserves requirements from Bin 10 as depicted in Table H.9. As for load, the wind regulating forecast changes every ten minutes, and as a result, the regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast shifts the wind regulating component reserves requirement from Bin 10 into Bin 7 (per Table H.9), and so the component reserves requirement changes accordingly.

The selection of component reserves using component hypothetical operational forecasts as depicted above is replicated for each ten-minute interval, assigning four component reserves requirements in each interval throughout the Study Term. The four components are combined into a single regulating reserves requirement as defined below.

Total Regulating Reserves Requirement

After the assignment of the component reserves requirements, each ten-minute interval of the Study Term exhibits values for load following reserves, wind following reserves, load regulating reserves, and wind regulating reserves. Each of these values is derived by comparing a unique component forecast to a unique actual value; in the case of load following, the load following forecast is compared to the average load for a given hour. For load regulating reserves requirements, the load regulating forecast is compared to the actual load observed at the same time. However, while adjusting operations for each of the four component factors is critical to maintaining system integrity, the components are not additive. Therefore, the wind and load reserve requirements are combined using the root-sum-square (RSS) calculation in each direction (up and down), assuming their variability in the short term independent or uncorrelated, by the RSS relationship in Equation 2. Then, the appropriate system L_{10} is netted from the result.

Equation 2. Total Regulation Reserves calculated from four component reserves using the root-sum-square formulation at time interval i:

$$\boldsymbol{Regulation\ Reserves_i} = \sqrt{LoadFollowing_i{}^2 + LoadRegulating_i{}^2 + WindFollowing_i{}^2 + WindRegulating_i{}^2} - L_{10}$$

Drawing from the first ten-minute interval in the example above as depicted in Table H.s 7 and 8, the component up reserves requirements were as follows:

Load Following = 271.5 MW
Load Regulating = 142.4 MW
Wind Following = 242.5 MW
Wind Regulating = 238.1 MW
East System L_{10} = 47.9 MW

Applying Equation 2:

$$\boldsymbol{Regulation\ Reserves} = \sqrt{271.5^2 + 142.4^2 + 242.5^2 + 238.1^2} - 47.9$$

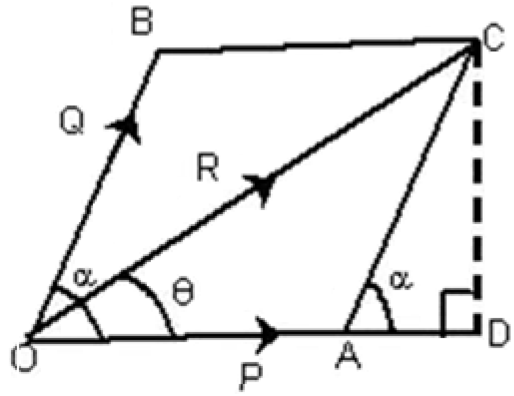
Per Equation 2, 409.8 MW of up reserves recommended for regulation reserve for the time interval between 10:00am and 10:10am, June 1, 2011 in PACE. In this manner, the component reserves requirements are used to calculate an overall reserves requirement for each ten-minute interval of the Study Term. A similar calculation is also made for the regulation reserve requirements pertaining only to the variability and uncertainty of load, which employs Equation 2 but applies zero reserves for the wind components. The incremental reserves assigned to wind generation demand are calculated as the difference between the total requirement and the load requirement. The results of these calculations can be quoted in hourly or monthly requirements by averaging the reserves requirements of all the ten-minute intervals within the specified hour or month. Annual reserves requirements are quoted as the average of the twelve monthly requirements.

Wind and Load Correlation

An important assumption underlying the application of Equation 2 is that there is no correlation between wind and load deviations. To test this assumption, this section describes an analysis of wind and load correlation.

The RSS equation is typically applied in the analysis engineering tolerances and supporting statistical concepts, and is derived from the Parallelogram Law[37].

Figure H.10 - Depiction of the Parallelogram Law



Equation 3. Vector combination as prescribed by the Parallelogram law in Figure H.10.

Resultant $\boldsymbol{R} = \sqrt{P^2 + Q^2 + 2PQ\cos\alpha}$.

If **P** and **Q** act at right angles, $\alpha = 90^{\circ}$, and $\cos(\boldsymbol{\alpha}) = 0$; $\boldsymbol{R} = \sqrt{P^2 + Q^2}$, which is equivalent to Equation 2.

The Parallelogram Law allows correlation to be constructive (with positive correlation) and destructive (with negative correlation). In cases of constructive correlation, the resultant (**R** in the illustration above, the parallelogram's diagonal) is increased as the angle (**α**) between (**Q**) and (**P**) is reduced. Destructive correlation causes the angle (**α**) to open wider, reducing the diagonal of the parallelogram, and reducing the length of the diagonal, **R**. The Law of Cosines can be used to illustrate a proof[38] that the cosine of angle **α** equals the correlation between vectors **P** and **Q** ($\cos(\boldsymbol{\alpha}) = \rho_{PQ}$).

In cases of zero correlation, the Parallelogram Law reduces to the RSS formulation (and **α** is a right angle, and the parallelogram is a square). For this Wind Study, rather than using two sides of a parallelogram to form a resultant (**R** in the illustration), four uncorrelated vectors

[37] A proof of the parallelogram law is available at: http://www.unlvkappasigma.com/parallelogram_law/

[38] http://www.johndcook.com/blog/2010/06/17/covariance-and-law-of-cosines/

corresponding to the component reserves for load following, load regulating, wind following, and wind regulating deviations are combined into a reserves requirement. The fact that there are four dimensions rather than two makes the process difficult to illustrate, but the effect is the same as in the two dimensional example above.

The Company applied the RSS formulation in its 2010 Wind Integration Study[39] after reviewing samples of the load and wind data used to perform the study[40], and reviewing studies by Idaho Power[41] and the Eastern Wind Integration and Transmission Study[42]. Since that time, additional studies have suggested use of this formulation directly[43] or noted that short term deviations from schedule in wind generation output and load are not correlated[44]. However, stakeholder interest has encouraged the Company to further review the correlation between wind and load reserve components.

Because reserves are intended to manage the deviations from expected load and wind generation output, the question becomes not whether the raw wind generation output and balancing area load are correlated, but rather whether the respective forecast errors between the Company's expected wind generation and load are correlated. These forecast errors drive the component reserves in the Wind Study, and reflect the level of reserves needed in real time operations. The analysis below assesses the correlation of deviations from forecasts for load and wind in both the hourly (following) and sub-hourly (regulating) timeframes.

Correlation Analysis

The forecast deviations for wind generation and load in the Company's BAAs were analyzed for correlation by performing a linear regression using the load deviation as an independent variable and the concurrent wind deviation as the dependent variable. Therefore, to estimate the East Wind Following deviation for a given time period, the East load following deviation was used as a predictive variable. The correlation between the two variables (load errors and wind errors) would be represented by the slope of the regression, and the predictive capability by the $\mathbf{r}^2$ (or goodness-of-fit). The procedure was followed for 2011 operational data applying the four component forecasts detailed previously for PACE and PACW. The results appear in Table H.12.

39 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, p. 19

40 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, Table 5, p. 6

41 http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/Addendum.pdf, pages 12, 20

42 http://www.nrel.gov/C821B4E9-F70E-4245-9C6D-D5CB68B670DC/FinalDownload/DownloadId-286D6B0AF14A941F45E5F431BACF4DCF/C821B4E9-F70E-4245-9C6D-D5CB68B670DC/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf, page 145

43 http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf, page 6E-9

44 http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf, page 92

Table H.12 - Results of Regression Analyses between Wind and Load Deviations

	Slope	r-Square
East Following	-0.097	0.45%
East Regulating	-0.087	0.63%
West Following	0.026	0.05%
West Regulating	-0.007	0.00%

The results indicate that while there is a calculable correlation between wind and load deviations in the data, the relationships are so weak such that neither explains the other, and so this relationship is not useful in an operational context. The value of the load deviation offers no ability to explain the wind deviation, and so the two are unrelated. This is consistent with the findings of wind studies noted above.

To illustrate the analysis, plots of the load and wind deviations (from their respective forecasts) have been prepared using 2011 operational data in Figures H.11 through H.14 below. Each point represents the respective deviation at any given time (a ten-minute interval for regulating deviations, a given hour for following deviations) by magnitude of the forecast error of load and wind, which would have to be managed by deploying reserves in real time operations. The magnitude of the load deviations are recorded on the horizontal (x) axis and the wind deviations on the vertical (y) axis. The correlation between the load and wind deviations is represented by slope of the (red) regression trend lines; a strongly predictive correlation would have little scatter about the line, while a weak, non-predictive correlation (with a low $\mathbf{r}^2$ value) would exhibit significant and varying amounts of scatter about the trend line.

Figures H.11 through H.14 demonstrate highly variable clouds of data, and the extension of each cloud along the horizontal axis suggest the load forecast deviations require more reserves than do the wind deviations. Additionally, the data do not follow the regression trend lines well; there is significant scatter and it varies from a dense population of occurrences in the middle to sparsely populated data at the ends of the line. These cloud patterns suggest factors other than load forecast error should be used to explain corresponding wind forecast error, and vice-versa.

For example, the greatest load deviations don't necessarily seem to occur at the same time as most of the greatest wind deviations, nor are the deviations necessarily small. The range about the red regression line for East Following (in Figure H.11) exhibits several wind following deviations of about +/- 300 MW at +100 MW load following deviation (line A) and a similar amount and range at -100 MW load deviation (line B). The data suggest that increased forecast errors in either direction for load neither increase nor decrease the expected error in the wind forecast.

Figure H.11 - PACE Following Regression Plot

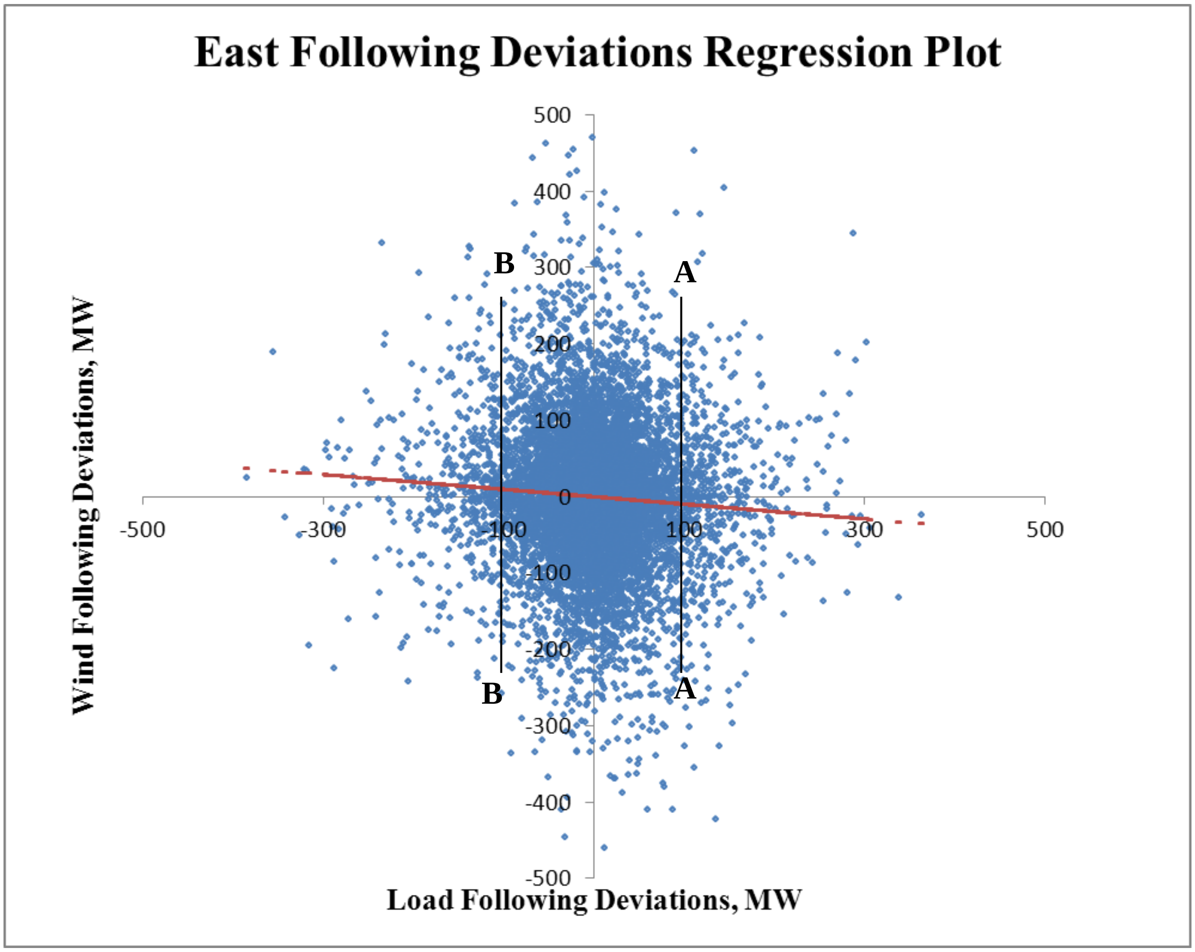
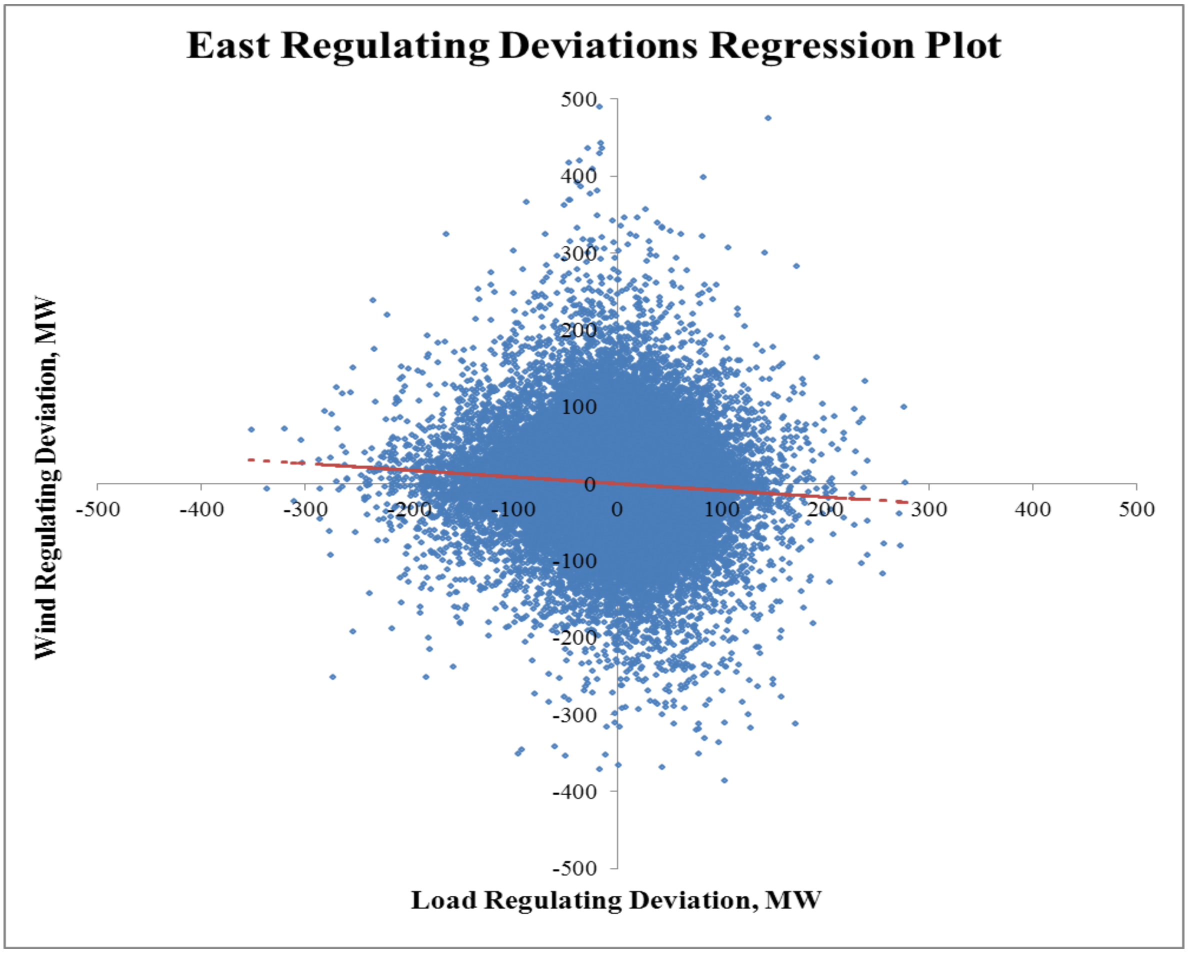
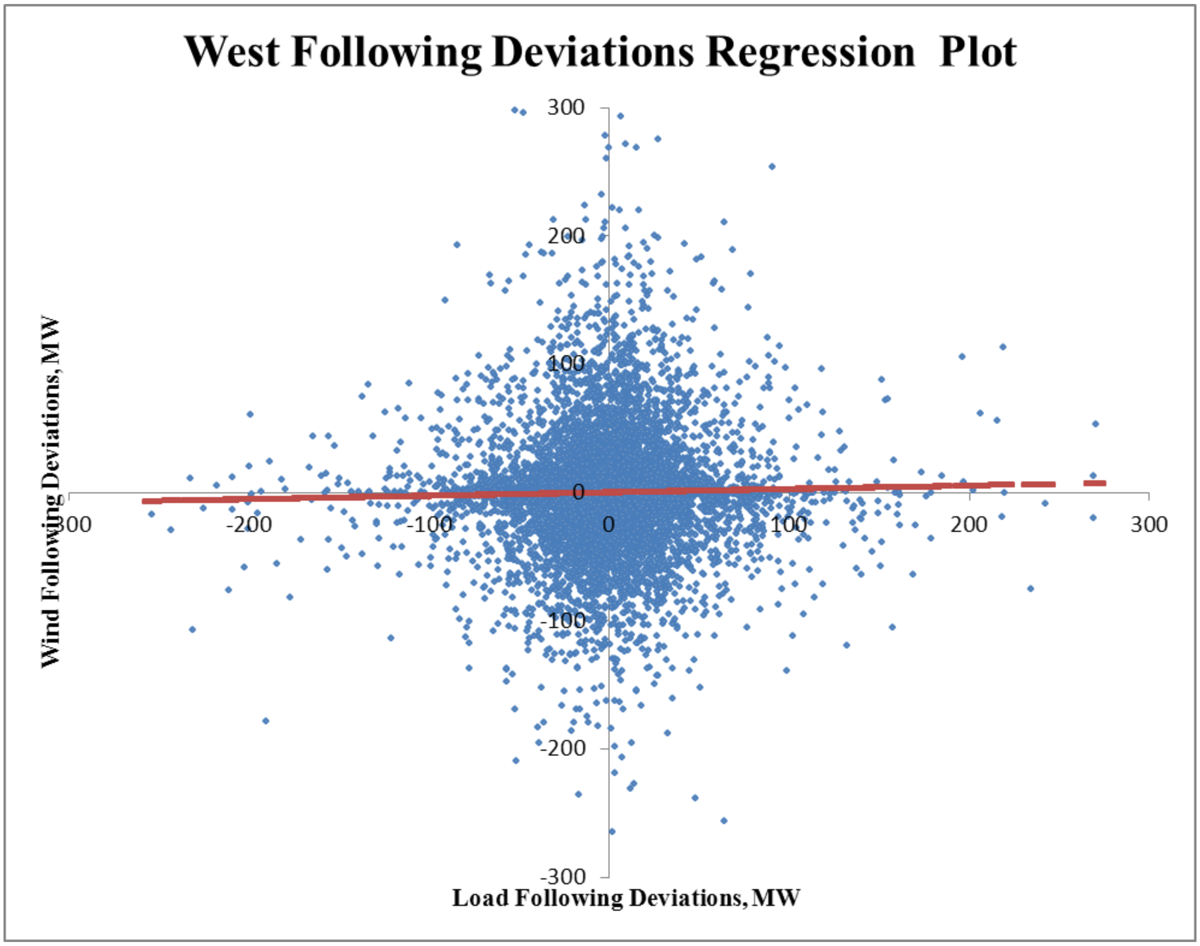


Figure H.12 - PACE Regulating Regression Plot[25]



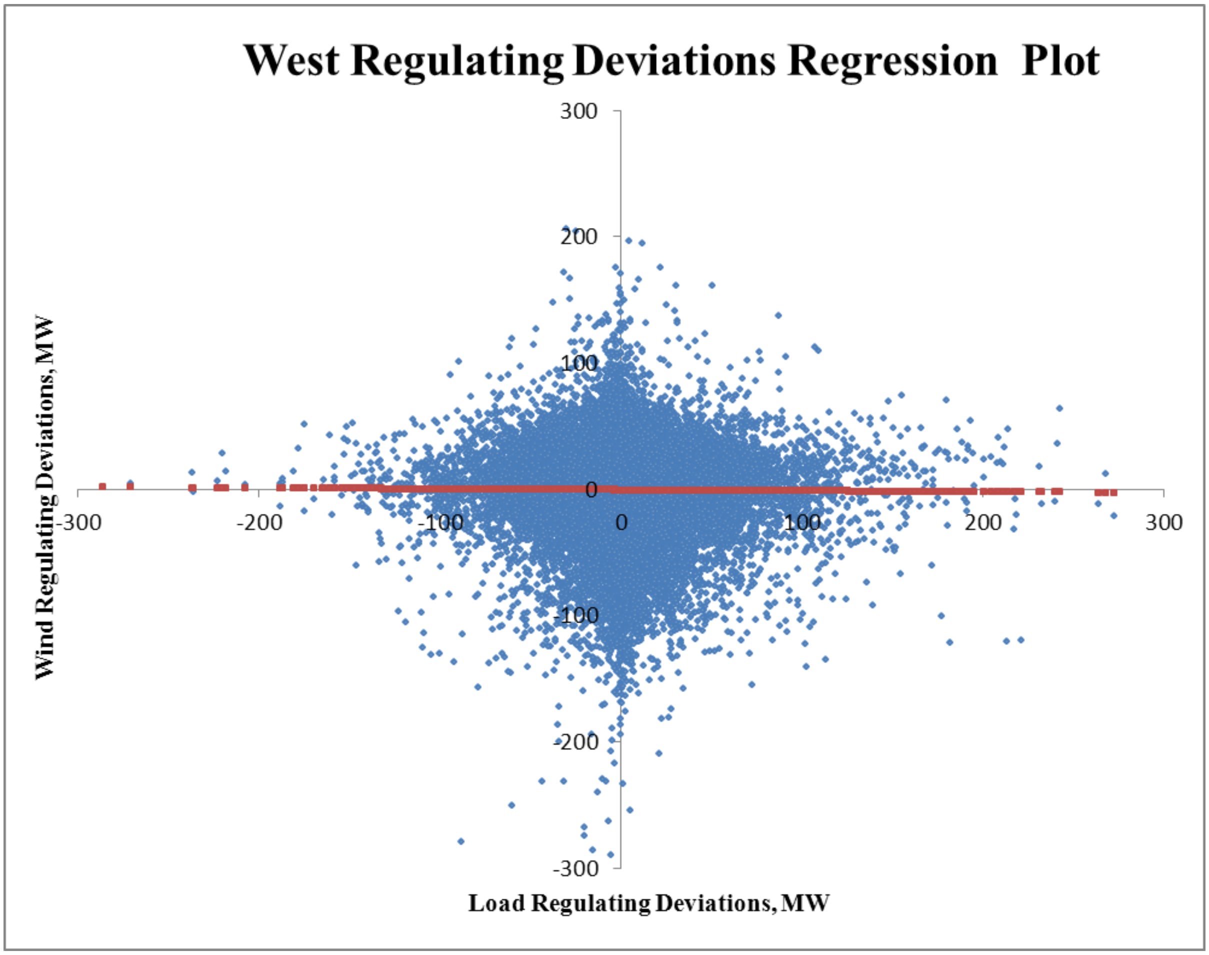
[25] Note cloud-like pattern of errors which is densest near zero, and the data does not tighten around the trend line.

Figure H.13 - PACW Following Regression Plot[26]



[26] Note another cloud of errors, with the red trend line describing little of the variation from one point to the other.

Figure H.14 - PACW Regulating Regression Plot[27]



3.3 Determination of Wind Integration Costs

3.3.1 Overview

Owing to the variability and uncertainty of load and wind generation, each hour of power system operations features a need to set aside operating reserve explicitly to cover load and contingency events inherent to the PacifiCorp system with or without wind in addition to contingency reserves. Additional costs are incurred with daily system balancing that is influenced by the unpredictable nature of wind generation on a day-ahead basis. To characterize how wind generation affects regulating margin costs and system balancing costs, the Study utilizes the PaR model, and applies the regulating margin requirements calculated by the method detailed in section 3.2.

[27] The dispersion in this cloud of data about the red regression trend line seems only to depend on how many data points are on either side of that line at any given point. Near the origin, there is a lot of data owing to most forecast errors being small, while at high deviations, there are very few points with which to assess fit, but there is scatter about the line.

PacifiCorp's PaR model, developed and licensed by Ventyx, Inc. 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, PacifiCorp developed five different PaR simulations. These simulations isolate wind integration costs associated with regulation margin reserves and enables separate calculation of wind integration costs associated with system balancing practice. The former reflects wind integration costs that arise 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.

The five PaR simulations used in the Wind Study are summarized in Table H.13. The first two simulations are used to tabulate operating reserve wind integration costs in forward planning timeframes. The approach uses a "P50" or expected wind profiles[28] and forecasted loads. The remaining three simulations support the calculation of system balancing wind integration costs. These simulations were run assuming operation in the 2013 calendar year, applying 2011 load and wind data. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis.[29] PacifiCorp resources used in the simulations are based upon the 2011 IRP Update resource portfolio.[30]

Table H.13 - Wind Integration Cost Simulations in PaR

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error
Regulating Margin Reserve Cost Runs					
1	2013	2013 Load Forecast	P50 Profiles	No	None
2	2013	2013 Load Forecast	P50 Profiles	Yes	None
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1					
System Balancing Cost Runs					
3	2013	2011 Day-ahead Forecast	2011 Day-ahead Forecast	Yes	None
4	2013	2011 Actual	2011 Day-ahead Forecast	Yes	For Load*
5	2013	2011 Actual	2011 Actual	Yes	For Load and Wind**
Load System Balancing Cost = System Cost from PaR simulation 4 (which uses the unit commitment from Simulation 3) less system cost from PaR simulation 3 *Wind System Balancing Cost = System Cost from PaR simulation 5 (which uses the unit commitment from Simulation 4) less system cost from PaR simulation 4*					

3.3.2 Calculating Operating Reserve Wind Integration Costs

To assess the effects of wind capacity added to the PacifiCorp system on regulating margin costs,

[28] P50 signifies the probability exceedence level for the annual wind production forecast; at P50 generation is expected to exceed the assumed generation levels half the time and to fall below the assumed generation levels half the time.

[29] The Study uses the June 29, 2012 official forward price curve.

[30] The 2011 Integrated Resource Update report, filed with the state utility commissions on March 30, 2012 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/2011IRPUpdate/2011IRPUpdate_3-30-12_REDACTED.pdf.

the reserve requirements were simulated in PaR using 2013 load and P50 wind forecasts. Both of the first two PaR simulations excluded system balancing costs. Simulation 1 applied only the regulation reserves required for load obligations to 2013 forecast load and wind generation on PacifiCorp's systems with a 2013 resource profile. Simulation 2 used the same inputs except for adding the incremental operating reserve demand created by the variable nature of wind generation.

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

3.3.3 Calculating System Balancing Wind Integration Costs

PacifiCorp conducted another series of three PaR simulations to estimate daily system balancing wind integration costs consistent with the resource portfolio, labeled as Simulations 3 through 5 in Table H.13. 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, the three additional PaR simulations included the incremental reserves from Simulation 2 and the unit commitment states associated with simulating the portfolio with the day-ahead forecasts.

Simulation 3 incorporated day-ahead forecasts for both load and wind, dispatching PacifiCorp's generation to the forecasts as though there were no day-ahead forecast error. This served as the starting point for separately determining load and wind balancing impacts on total system balancing costs. Simulation 4 paired 2011 actual loads with day-ahead forecasts for wind generation, isolating the error due to load forecasting, and also applied the unit commitment state generated by Simulation 3 to capture system operations based on the day-ahead load forecasts. Simulation 5 incorporates actual wind generation output, thereby including forecast error for load and wind, and applied the unit commitment state generated by simulation 4. The change in system costs (Simulation 5 less Simulation 3) represents the total cost of day-ahead balancing on PacifiCorp's BAAs. Dividing the day-ahead wind balancing costs (Simulation 5 minus Simulation 4) by the volume of wind generation in the portfolio yields a system wind balancing cost on a per-unit of wind production basis.

3.3.4 Application of Study Results to Integrated Resource Plan Portfolio Modeling

The Study results are applied in the 2013 IRP portfolio development process as part of the costs of wind generation resources. In the portfolio development process using the System Optimizer (SO) model, the wind integration cost on a dollar per megawatt-hour basis is included as a cost to each wind resource's variable operation and maintenance cost. The exception is for prospective wind resources that could be located in the Bonneville Power Administration (BPA) balancing authority. The variable operation and maintenance adder for these resources includes BPA's variable integration charge[31]. The estimated wind integration cost is applied in the SO model (rather than increasing regulating margin) because the SO model builds least cost resource portfolios to meet system coincident peak loads with an assumed planning reserve margin. In meeting this coincident system peak capacity requirement, the SO model does not explicitly

[31] BPA's Variable Energy Balancing Service for wind resources is modeled at $1.23/kW-month, per their 2012 rate schedule, which at a 35% capacity factor equates to a charge of just over $4.80/MWh. The BPA rate schedule is available at: http://transmission.bpa.gov/Business/Rates/documents/2012_rate_schedules.pdf

evaluate operating reserve requirements. While operating reserve requirements are not explicitly in the SO model, the estimated cost of wind integration is accounted for in the development of resource portfolios.

Once candidate portfolios are developed using the SO model, additional analyses are performed using PaR, which can evaluate incremental operating reserve needs. Therefore, when performing IRP risk analysis using PaR, specific operating reserve requirements consistent with this wind study will be used.

When modeling the production costs and risk analyses of resource portfolios in the PaR model, the incremental reserve requirements, due to additional wind plants, are incorporated as part of the PaR model's total reserve requirements. These incremental reserve requirements reflect the amount of reserves required in PACE and PACW for the regulation of wind resources. The cost impact of holding this incremental spin reserve requirement is embedded in the total production cost, but cannot be isolated for reporting purposes.

3.3.5 Allocation of Operating Reserve Demand in PaR

The five PaR Simulations require operating reserve demand inputs consistent with the Company's supply portfolio are input 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.[32] Table H.14 shows these reserve categories and indicates which ones are used for the study. Reserve requirements calculated in the study are allocated into these PaR reserve categories per below, and are supplemental to the contingency requirements calculated within PaR.

Table H.14 - Operating Reserve Categories Used by the PaR model

Input Field	Definition	Reserve Requirements Entered
AS1	Up Regulation	Regulation
AS2	Down Regulation	not used
AS3	Spin	Ramp and Contingency
AS4	NonSpin	Contingency
AS5	30 Minute NonSpin	not used

The regulation up and regulation down reserves in PaR are considered spinning reserve that must be met before traditional spinning and non-spinning reserve demands are met. The incremental operating reserve demand needed to integrate wind generation was assigned in PaR as regulation up. As down regulation reserves are a deployment of generation already committed to load, this feature was omitted from the Study. The traditional spinning and non-spinning reserve inputs are used for ramp and contingency reserve[33] requirements. Contingency reserve requirements

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

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

remain unchanged among all PaR simulations in the Study. The 30-minute non-spinning reserve product is not represented in PacifiCorp's supply portfolio, and thus it is not used. Unused regulation up reserve supply can be used in PaR to satisfy spinning or non-spinning reserve demand.

The PaR model balances the system hourly, committing adequate generation to serve the forecasted net system load and meet each hour's respective reserve requirements. In actual operations, any deviation from the load forecast may cause the reserves specified to be deployed (should the net system load be greater than expected) or for the amount of open generation capacity to be increased (should the net system load be less than expected). Because the direction of the deviation, greater or lesser, is unknown and random, this calculation of the cost to hold reserves above the generation required to meet forecast load is assumed to be unbiased to actual intra-hour outcomes.

4. Results

The regulating margin required to manage fluctuations in load and wind generation output are the sum of the ramp and regulation reserve requirements. The ramp reserve is dependent only on the observed load and wind generation in the operational data used throughout the Wind Study. The regulation reserve requirement is calculated by the methods detailed in section 3.2. Table H.15 below summarizes the regulating margin requirements as calculated by the Study.

Table H.15 - Regulating Margin Requirements Calculated for PACE and PACW (MW)

	West BAA	East BAA	Combined
Load-Only Regulating Margin	147	247	394
Incremental Wind Regulating Margin	54	131	185
Total Regulating Margin	202	378	579

The operational data used to calculate these results is based on 589 MW of wind capacity installed in PACW, and 1,526 MW in PACE. Additional wind resources added to resource portfolios in the 2013 IRP contribute a pro-rated regulating margin requirement in PaR model simulations based on these results[34].

4.1 Production Cost Results

As described in section 3.3 and detailed in Table H.13, PacifiCorp applied the reserve requirements calculated in this Wind Study to a production cost simulation in the Company's PaR model. For the regulating margin costs, the regulating margin required to manage variability due to load and wind on PACE and PACW was applied using a "with and without" approach; the margin required only to manage disturbances in load was modeled in a production cost simulation, then compared to a simulation run with the regulating margin necessary to manage load and wind disturbances. The regulating margin costs represents the costs incurred to hold additional reserves for wind to manage hour-to-hour operational disturbances, whereas the

[34] The regulating margin requirement added for potential West wind developments will be the ratio of calculated incremental reserve requirement to total installed capacity, or 9.2% of the proposed generating capacity (54/589); while for East wind developments it will be 8.6% (131/1526).

system balancing costs are incurred managing the deviation between the day ahead forecast for wind production and actual recorded production on PacifiCorp's Company-owned and contracted wind resources. Transmission customers' wind resources' day-ahead variability and uncertainty are excluded from the system balancing calculation. Wind integration costs are the sum of the regulating margin and system balancing costs, as presented in Table H.16:

Table H.16 - Nominal Levelized Production Cost Results for the 2012 and 2010 Wind Studies

	Regulating Margin Cost ($/MWh)	System Balancing Cost ($/MWh)	Wind Integration Cost ($/MWh)
2012 Wind Study	$2.19	$0.36	$2.55
2010 Wind Study	$8.85	$0.86	$9.70

The 2010 Wind Study's production cost results are presented for comparison. The 2012 Study's analysis reflects a significantly depressed commodity price environment when compared to the 2010 Study; this is chiefly responsible for the cost differential. Additionally, the 2010 Wind Study's published system balancing cost includes day-ahead load forecast error, which should not be attributed to wind resources.

4.2 Additional Scenarios

To further understand differences around the set-ups of the Study and respond to requests of IRP stakeholders and the TRC, the Company has evaluated several scenario calculations to highlight the effect of selected changes in assumptions on the calculated regulating margin requirements. For the purposes of these scenarios, the same 99.7 percent tolerance level (and subtraction of L_{10}) was applied to the calculation method described above using 2011 operational data unless specified otherwise.

Historical Evaluation

The operational data available throughout the Study Term permits the estimation of historical reserves requirements. This may inform future planning, as the amount of wind generation capacity installed in PacifiCorp's system has steadily increased through the Study Term. Applying the method above to all the operational data in the Study Term, the following historical regulating margin requirements are calculated, as depicted in Table H.17. Table H.18 breaks out the incremental operating reserves calculated to manage wind generation.

Table H.17 - Historical Reserves Calculated throughout the Study Term (MW)

	Regulation West	Regulation East	Ramp	Total	Average Wind Capacity, MW
2007	184	194	134	512	606
2008	184	193	122	499	787
2009	145	211	121	477	1364
2010	152	261	122	534	1810
2011	149	302	128	579	2126

Table H.18. Incremental Reserves Due to Installed Wind Generation Capacity (MW)

	Regulation West	Regulation East	Ramp	Total	Average Wind Capacity, MW
2007	15	11	2	28	606
2008	24	14	3	40	787
2009	31	45	4	80	1364
2010	40	78	6	124	1810
2011	50	126	9	185	2126

Concurrent Evaluation

The calculations in this scenario are made for the load and wind deviations combined concurrently, by adding their concurrent errors, producing state bins and integrating the results for following and regulating reserves for load and wind separately. Despite the estimation of load and wind quantities separately in real time operations, and given no indication that short-term changes in load and wind are correlated[35], many stakeholders requested a calculation of the estimated reserves with implied correlation and other characteristics that may be observed in the short term variations of load and wind. The results of these calculations are presented in Table H.19.

Table H.19 - Concurrent Netting of Load and Wind Errors Scenario Results (MW)

	Regulation West	Regulation East	Ramp	Total
Scenario	160	279	128	567
2012 Study	149	302	128	579

The combination of errors and system state were each made following the load minus wind generation paradigm and the resulting differences were used to estimate reserves positions. This approach imputes the spurious correlation mentioned in section 3.2.5 into the results.

Reliability Based Control Market Structure

A new control performance paradigm featuring a 30-minute balancing market is under regional evaluation. Per current operational practice, the 60-minute market and operational paradigm is the base of the Wind Study design. However, to assess the potential benefits of a 30-minute clearing market for PacifiCorp's customers, an alternate calculation has been prepared by reducing the load and wind forecasting time interval to 30 minutes, and also reducing the persistence forecast intervals for regulation to 30 minutes for wind and load demands. Table H.20 compares the regulation reserves for the 30-minute balancing market scenario and the default 60-minute balancing market case for PACE and PACW. This calculation assumes adequate market depth at all 30-minute intervals such that the Company can rebalance system deviations from the market. The ramp obligation is assumed to remain supplied by the Company's hourly generation planning.

[35] Western Wind and Solar Integration Study, prepared by NREL, (May, 2010), p. 92. The report is available for download from the following hyperlink:
http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf

Table H.20 - 30-minute Balancing Interval Scenario Results (MW)

	Regulation West	Regulation East	Ramp	Total
Scenario	105	233	128	466
2012 Study	149	302	128	579

Combination of PACE and PACW

The calculations can also estimate the effect of combining PacifiCorp's two BAAs, into a single, monolithic balancing authority area. This assumption is that these calculations would mimic the effect of significant transmission development, eliminating the seams between the PACE and PACW. The respective load and wind errors for following and regulation are combined concurrently (East plus West) and the resulting component reserves demands are compared to those required by the default method described above for separate BAAs in Table H.21. However, the Company is uncertain at this time exactly how revised operational and forecasting practices would affect this scenario, and so further updates are possible.

Table H.21 - Regulating Margin Requirements Calculated Assuming a Single PacifiCorp Balancing Authority Area (MW)

	Regulation	Ramp	Total
Scenario	356	121	477
2012 Study	451	128	579

5. Summary

The purpose of this Study is to determine the additional reserve requirement to integrate wind resources into the Company's existing resource portfolio and determine a cost that is used in the portfolio development stage of the 2013 IRP.

The Study is based on actual historical data in ten-minute intervals for both load and wind generation, as well as actual historical day-ahead load and wind generation forecasts, in the Company's east and west balancing authority areas. The data were reviewed for anomalies, and revised prior to be applied in the Study.

The Study defined the two components of the regulating margin to include ramp and regulation reserves:

1) Ramp: A number of factors (fluctuations in customer demand, spot transactions, varying amounts of generation produced by variable resources such as wind and solar generation) cause the net balancing load to change from minute-to-minute, hour-to-hour continuously at all times. This variability (increasing and decreasing load) requires ready capacity to follow continuously, through short deviations, at all times. Treating this variability as though it is perfectly known (as though the operator would know exactly what the net balancing area load would be a minute from now, ten minutes from now, and an hour from now) and allowing just enough generation flexibility on hand to manage it defines the ramp reserves requirement of the system. The amount of ramp reserve required is half the difference

between the net balancing area load (load minus wind generation output) from the top of one hour to the next.

2) Regulation: Deviations from forecasted load or wind generation are not considered contingency events, yet these events still also require that capacity be set aside. Reserves maintained to manage uncertainty around the net system load is called regulation reserve. The Company has defined four components of regulation reserve (load following, load regulating, wind following, and wind regulating), estimated by comparing actual data to hypothetical forecasts. The four components are uncorrelated over operational generation planning's short time frames; and so the requirements to cover them are combined using a root-sum-square method into a single regulation reserve requirement for each time interval. The average regulation reserve requirement over any given timeframe expresses the regulation requirement for that timeframe.

To summarize, regulating margin represents operating reserves the Company holds over and above the mandated contingency reserve requirement to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts; ramp reserve and regulation reserve. The ramp reserve represents a minimum amount of flexibility required to follow the actual net system load (load minus wind generation output) with dispatchable generation. The regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors about the net system load, and consists of four components: load following, load regulating, wind following, and wind regulating.

The four components of the regulation reserves were calculated as the differences between the respective hypothetical operational forecast and actual data, sampled at a 99.7th percentile. The 99.7th percentile is selected to remove the most extreme deviation values from the assessment of the forward reserve requirements, while still providing sufficient reserve to prevent operations from running out of regulating margin due to the uncertainties prevalent in hour-to-hour power operations. In the past, the Company managed its balancing areas to a target called the Control Performance Standard 2 (CPS2), which specified a limited number of excursions from a net system interchange target. Since March 1, 2010, the PacifiCorp has been participating in a regional field test of the Reliability Based Control standard, which replaces the system interchange requirements with a regional frequency-based requirement. Among other changes, this new operational paradigm means the Company responds to area control error depending on whether their respective area control error is exacerbating or mitigating the frequency excursion at the time. As the frequency depends on the instantaneous balance between loads and resources throughout the entire Western Interconnection, the Company must plan to supply its own reserve requirements assuming its area control error is exacerbating system frequency. This has modified reserves planning from considering CPS2 to an avoidance of using contingency reserve for anything other than specified contingency events, as that is not allowed. Therefore, the regulating margin requirement evaluated in each time interval of the Wind Integration Study is intended to cover all anticipated uncertainties in short term load and wind behavior, consistent with the requirement of the Company to meet its firm load obligations and not deploy contingency reserve to cover what it should manage with regulating margin.

The sampled component reserve requirements are then backcast against the hypothetical operational forecasts and data for each ten-minute interval of the study. The resulting (selected) component reserve requirements are then combined using the root-sum-square method to arrive at the total regulation requirement, by East and West BAA (PACE and PACW, respectively). This requirement is reduced by each BAA's respective L_{10} value[36][37].The total regulating margin is the sum of the regulation requirement plus ramp reserve. Table H.22 below is a summary of results.

Table H.22 - Regulating Margin Requirements Calculated for PacifiCorp's System (MW)

	West Regulation	East Regulation	Ramp	Combined
Load-Only Reserves	99	176	119	394
Incremental Wind Reserves	50	126	9	185
Total Reserves	149	302	128	579

The cost to hold the incremental regulating margin to integrate wind resources is estimated using the Company's PaR model (a production cost model set up to simulate the operation of PacifiCorp's electrical system)by calculating the difference in production costs with and without the incremental reserves to integrate wind resources using the projected Company's load and resource portfolio in 2013. This calculation results in the intra-hour reserves costs detailed in Table H.23. The day-ahead load and wind forecast data are used to commit the generation resources in the PaR model, and then it is set to simulate operations serving the actual system loads and received wind generation, isolating the effect of wind generation forecasts and actual generation in a three-stage process. This calculation yields the inter-hour/system balancing cost, also detailed in Table H.23:

Table H.23 - Wind Integration Costs

Study	2012 Wind Integration Study
Wind Capacity Penetration	2126 MW, 2011 Operational Data
System Assumption	2013 PacifiCorp System
Tenor of Cost	1 year levelized, 2012$
Hourly Reserve ($/MWh)	$2.19
Interhour/System Balancing ($/MWh)	$0.36
Total Wind Integration ($/MWh)	$2.55

The costs calculated in this study reflect the current market conditions for natural gas and electricity based on the June 29, 2012 official forward price curve. As these market conditions change, so will the value of the operating reserves required to meet the systems' regulating margin requirements. The total wind integration costs displayed in Table H.23 are used in the Company's System Optimizer model for IRP portfolio development, while the incremental regulating margin requirements for integrating wind displayed in Table H.22 are used to support IRP portfolio production cost modeling using the PaR model.

[36] The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails.

[37] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to: http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf

APPENDIX I – STOCHASTIC LOSS OF LOAD STUDY

This appendix contains the Cost and Reliability Analysis of Planning Reserve Margins Final Report received from Ventyx as requested by PacifiCorp to support planning reserve margin modeled in the 2013 Integrated Resource Plan.

Cost and Reliability Analysis of Planning Reserve Margins

Pacificorp

Final Report

27th February 2013 – Version 2.1

Prepared by:

Jason E. Christian, PhD
Ventyx Advisors

1 INTRODUCTION

1.1 Workflow Overview

Figure 1 below shows the general workflow for the analysis of reserve margins. The objective of the study is to measure the costs and benefits of alternative reserve margins. The benefits, in terms of this study, are the increased reliability associated with higher reserve margins as measured by the Planning

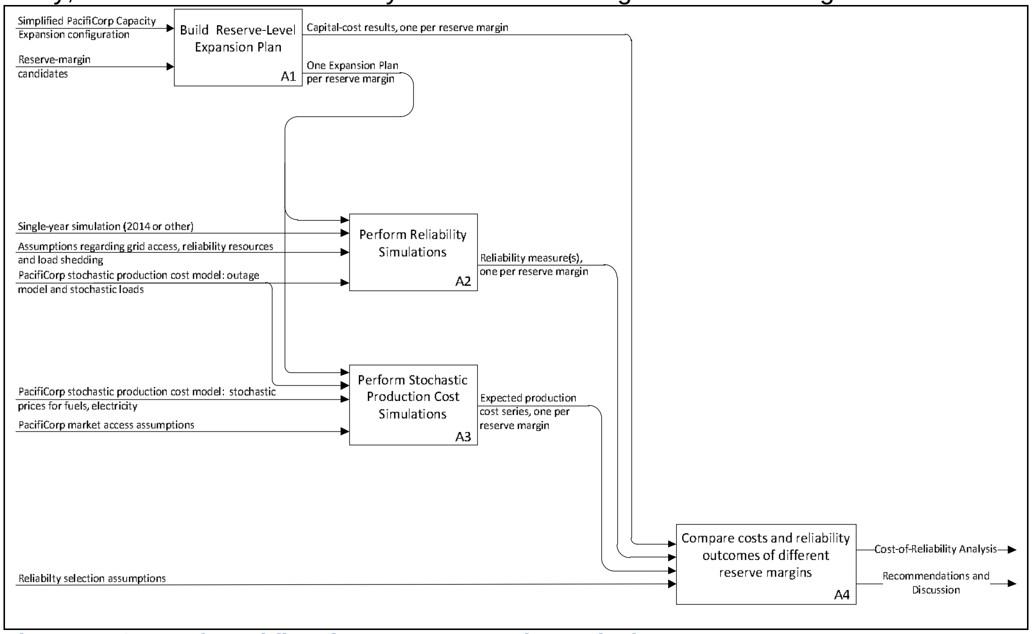


Figure 1. General Workflow for Reserve Margin Analysis

and Risk (PaR) Reliability Model (process A2 in Figure 1). The costs are (1) capital costs reported by the System Optimizer (SO) capacity-expansion model (process A1 in the figure) and (2) expected production costs reported from the PaR stochastic Production Cost model (process A3 in Figure 1). The general workflow includes as well the analytic process A4 where the results of processes A1, A2, and A3 are brought together and analyzed.

The general analysis illustrated in Figure 1 includes two distinct stochastic PaR models. The Reliability Model differs, in general, from the Production Cost model in that the Reliability Model assumes less (or no) access to markets or other grid resources; the intent of the Reliability Model is to measure the ability of a system to maintain reliability without relying on the rest of the grid. The self-reliance assumption is not, in general, appropriate for estimation of production cost; for production cost modeling the expected access to markets, to enable economy purchases or sales of generation, is modeled.

Reliability measures, including expected unserved energy (EUE, typically measured in MWh or GWh), Loss of Load Hours (LOLH), and Loss of Load Probability (LOLP, typically measured in days of outage per ten years) are available from both the Reliability Model and the Production Cost Model. Which measure to use to evaluate the reserve margin choice depends in part upon the reliability policies of the utility and its regulators and stakeholders, and in part upon the uses to which it will be put. For example, in the case of Pacificorp, the company already assumes limited market access, substantially less than the transmission-supported emergency-power facilities offered by the Northwest Power Pool (NWPP) reserve-sharing arrangements. For the Reliability Model there is no market access outside of the firm Front Office Transactions that are parts of the capacity-expansion process. See section 1.3.1 for further discussion of the assumptions regarding different types of external power.

1.2 Major Assumptions

1.2.1 Market Access and Emergency Power in the Reliability and Production Cost Models

This study, along with other elements of Pacificorp's IRP modeling processes, makes a strong distinction between the availability of external power for capacity-planning purposes and for forecasts of the expected costs of operating that capacity. For capacity planning purposes, external purchases are limited to Front Office Transactions (FOT's), which in general require that Pacificorp have the firm capacity to bring that power from an external trading point (such as the MidC hub) into its service territory, and that there be sufficient available generating and transmission capacity to allow counterparties to reliably deliver on those contracts to the trading point. The FOT capacity assumptions are, then, the capacity-model equivalent of conditions for trading capacity in systems where there are formal capacity markets. In contrast, in the stochastic production cost models, it is assumed that reasonably liquid markets exist at various points around the system, and that in actual near-real-time operations (for example day-ahead) sufficient transmission capacity will be available, at a price. To some extent lack of availability of transmission near real time is reflected in the production cost model by energy price volatility. In forecasting the expected costs of operating a portfolio, assumptions regarding the prices that are available to generators are important, but for the purposes of planning, and satisfaction of planning reserve requirements in particular, only the more restrictive assumptions embodied in the FOT assumptions are used.

The restrictive assumptions used in the capacity expansion modeling are relaxed in the reliability modeling specifically to capture the contributions to two measures of reliability---Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) provided by the reserve-sharing arrangements of the Northwest Power Pool (NWPP). The reliability impacts are one of the contributions of the NWPP arrangements; a major production- cost savings, shared by Pacificorp and other members of the Pool, is associated with sharing the burden of providing operating reserves against the single largest contingency of the full pool, rather than having each participant holding reserves against its own largest contingency; this effect is captured in the current modeling, as in the modeling in support of previous IRPs, through a reduction in the modeled ancillary-services requirements. The reliability contribution is captured in two ways: by approximating the energy delivered by the Pool in the first hour of each simulated loss-of-load episode, and by reducing the number of LOLH by 1 per episode. It should be noted that the traditional LOLP measure, which does not distinguish between episodes, is not effected by this calculation: each time there is a simulated call on NWPP emergency energy counts as a reliability event (but of shorter duration and smaller energy magnitude than otherwise). This allows an estimation of an additional cost savings associated with participation in the NWPP arrangements: this participation allows the same reliability to be achieved (as measured by LOLH or EUE) at a lower reserve margin.

1.2.2 Selection of Reliability Year

The objective of the modeling workflow is to estimate the cost and reliability consequences of different reserve margins, supporting a reserve margin recommendation which can, if adopted, be used as a target for future-year planning. As such it is neither necessary nor desirable to simulate every possible year. It is sufficient to do the analyses for a single year. For this study we selected 2014 as the reliability year, as it is the earliest year when a change in the Reserve Margin could have an effect, and it is the year when a new combined cycle, whose construction is already committed, will come into service in Utah.

1.2.3 Topology

The various simulations used in this study used variants of the current Pacificorp planning topology illustrated in Figure 2 below. The capacity expansion model and the production cost simulations used the full detailed version, while the reliability model used the 5-zone aggregation indicated by the blue-shaded areas in the figure. The reasoning behind this aggregation is discussed in section 3.2 below.

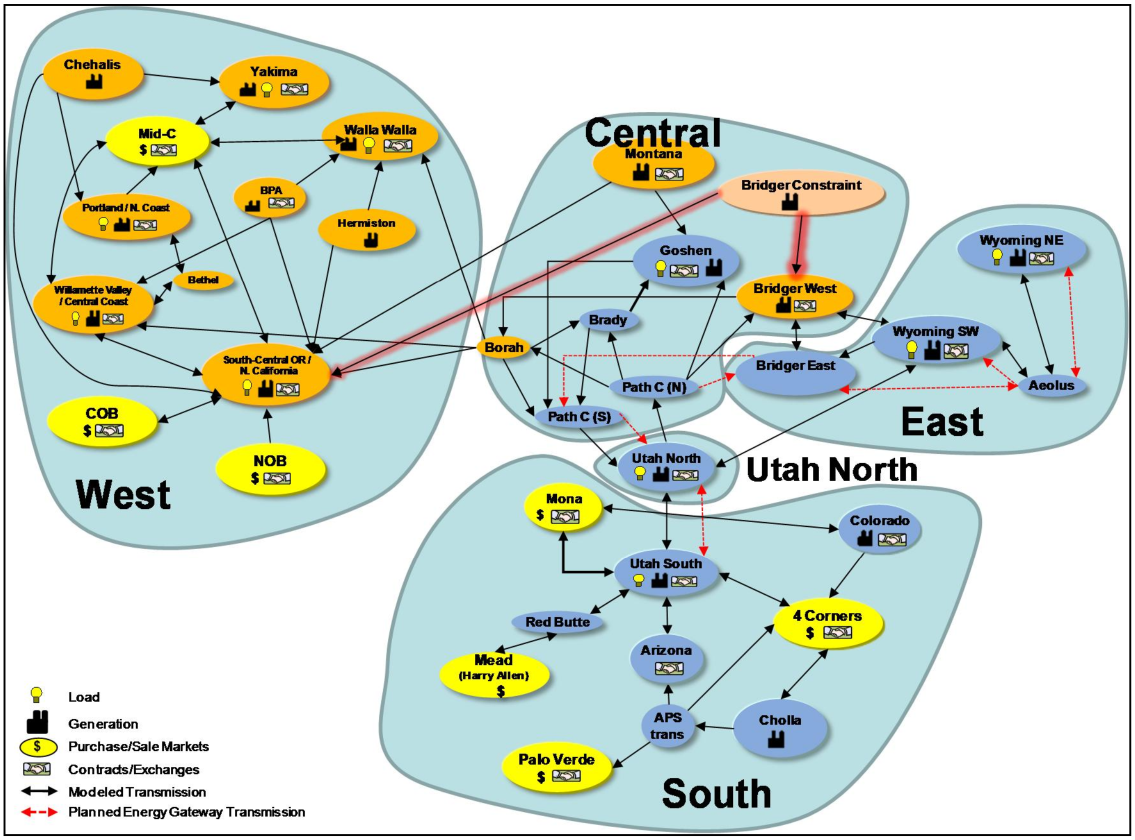


Figure 2. Pacificorp Planning Topology

1.2.4 Load Volatility calibration

Volatility of loads is one of the key drivers of the utility resource planning process and, therefore, of the associated reliability and cost modeling. There are three major sources of fluctuations in demand: the highly predictable hour-to-hour and day-to day shape, the short-term weather effects, also highly predictable to the extent that the weather drivers are predictable, and the longer-term variability in the size and composition of the utility's customer base. In this study the Reliability Year is 2014 (see Section 1.3.2), near enough to eliminate most of the third source of volatility. The modeling therefore uses only the mean-reverting short-term process that is at the core of the PaR stochastic model.

The core of a utility load forecast is a shape that includes an expected peak load. Suppose, for simplicity, that the only source of load volatility is "weather;" in a summer-peaking system this might be the highest daytime high temperature expected during a forecast period, that occurs on a weekday. The load forecaster has good information on the distribution of daily high temperatures at a location; again, for simplicity, assume they obey a normal distribution and the load (or weather) forecaster knows the mean and standard deviation of the distribution. There are about 20 weekdays in a month; the expected high temperature is therefore the expected maximum from 20 draws. The peak load forecast is a forecast of this random variable, with a probability of being exceeded.

The stochastic reliability model performs Monte-Carlo experiments to simulate the ability of the power system to serve loads during occasional high-impact events involving unusually high loads in combination with major outages of generation. The model therefore needs to make draws from the distribution around the expected peak with an appropriate frequency. One approach would be to use a weather-based load model directly, take draws of the weather variables (such as heating-degree-days and cooling-degree-days); this approach would, with a well-estimated load model, produce an appropriate distribution of loads (and of the derived measure peak loads). The alternative approach used here is to compare two peak load forecasts, with different probabilities of exceedence; the expected value of the peak load is the higher-probability-of-exceedence forecast, which is shocked by a stochastic scalar that produces the lower-probability-of-exceedence forecast from the higher-probability forecast with the frequency implied by probabilities.

Pacificorp provided a 1-in-10 exceedence forecast for 2014 of 10,331 MW; this is the expected peak used in this reliability study as well as in the rest of the IRP stochastic simulations. Pacificorp also furnished a 1-in-20 exceedence forecast of 10,712 MW for 2014. We model this by setting up a stochastic scalar, with an expected value of 1, to reach a value of 10712/10331=1.0369. This should occur in 1/20 of the Monte-Carlo scenarios; noting that we are doing daily draws, there are for each Monte-Carlo scenarios about 20 weekday opportunities to reach this level. So we seek a distribution that has a mean of 1 and that reaches the critical value of 1.0369 in 1/20 of the scenarios, where each scenario has 20 weekday opportunities: we seek the distribution that has 1-(1/20^2) =99.75% of its values less than 1.0369. The 99.75th percentile of a standard normal distribution (mean of 0 and standard deviation of 1) can be computed with the Excel formula =NORMINV(0.9975,0,1), which returns the value 2.807034. This allows the computation of a target converged volatility $\sigma^{\mathrm{T}} = \frac{1.0369-1}{2.807034}$ =0.013148. To check, note that the Excel formula =NORMINV(0.9975,1, 0.013148) returns the value 1.036907.

The stochastic model used for both the Reliability and the Production Cost model uses a mean-reverting model with a mean reversion rate 0.4. The mean reversion rate was not estimated; rather it is an approximate value, similar to other values estimated for power customers in the west, and is consistent with the weather patterns in the region (where both winter and summer weather fluctuations tend to have a duration of several days). It can be shown (Christian 2008a) that a mean reverting process with mean reversion rate α will, on multiple iterations, have a distribution with a standard deviation that converges to a target σ^T if it has a short-term volatility (the standard error of the shocks to the mean reverting process) of

$$\sigma^S = \sigma^T\sqrt{1-(1-\alpha)^2}.$$

Applying the converged target σ^T we compute a short-term volatility σ^S =0.013148$\sqrt{1-(0.6)^2}$ =0.0105183. This value, as well as the mean reversion rate of 0.4 was applied to all of the power customers in the standard Pacificorp stochastic planning and risk model. The existing correlation coefficients estimated for the prior IRP were retained, so as to capture the load diversity between load areas.

2 CAPACITY EXPANSION MODEL

The capacity expansion model used in this study used the assumptions used in other parts of the Pacificorp IRP process, but building to different reserve margins. The primary resource expansion options used to satisfy the requirements for capacity expansion were a series of Front Office Transactions (FOT), that are assumed to be able to reliably deliver power to several points around the Pacificorp system (COB, Goshen, Mead, MidC, Mona, NOB, Portland, Utah, Willamette Valley, Southern Oregon/California, and Yakima), as well as gas-fired CC-GT stations in Utah and in the Southern Oregon/California zone. The FOT transactions are priced at the forward electricity prices forecast at their zones, plus a zone-specific adder. The capacities that may be purchased of these FOTs reflect Pacificorp planning assumptions. FOTs may be either for a fixed amount (determined by the System Optimizer (SO) model) for the full year, or for Third-Quarter High Load Hours (Q3 HLH, the 16 hours beginning at 6 am and ending at 10 pm). SO was then run 11 times, for each of the integer reserve margin levels 10% through 20%.

The results of these runs are summarized in Table 1 below. Overall, the model has a preference for the Q3-HLH variant of the Front Office Transactions, up to the assumed limits on those transactions. This is not surprising, since the driver behind capacity expansion is increasing the reserve margin at the system coincident peak, which in the model occurs in the third quarter, and these resources have no fixed cost and only a small charge above market.

All expansion plans included the addition of one Class F CC-GT in the Southern Oregon-Northern California zone, and one in the Utah-North zone, with a combined capacity of 1,719 MW. At reserve-margin 16%, the model requires more capacity that can be provided by additional FOTs, so an additional CC-GT is added in the Southern Oregon-Northern California zone. The attractiveness of this location can be inferred from the topology map (Figure 2 above): this is a transmission hub on the Pacificorp system with the ability to provide capacity to much of both the western and eastern parts of the system. When the additional CC-GT is added at the 16% level, the solution plans' selections of FOT falls to accommodate the physical plant, then increases again as the reserve margin requirement increases.

Table 1. Expansion Plans as Reserve Margins Increase: 10%--20%

Reserve Margin	Flat FOT	Q3 HLH FOT	*Total FOT*	Physical Plant	*Total*
10	282	386	*669*	1,180	*1,849*
11	283	487	*770*	1,180	*1,950*
12	284	587	*871*	1,180	*2,051*
13	287	685	*972*	1,180	*2,152*
14	293	780	*1,073*	1,180	*2,253*
15	299	875	*1,174*	1,180	*2,355*
16	306	431	*736*	1,719	*2,456*
17	312	525	*838*	1,719	*2,557*
18	319	620	*939*	1,719	*2,658*
19	273	767	*1,040*	1,719	*2,759*
20	280	861	*1,141*	1,719	*2,860*

3 RELIABILITY MODEL

The Reliability Model allows an evaluation of the ability of a utility to serve its own loads with specified resources, in this case a series of expansion plans (as described in the previous section) selected to meet various reserve margins.

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3.1 Reliability Model Description

The Reliability Model is a stochastic implementation of the Planning and Risk (PaR) chronological unit-commitment and dispatch simulator, which finds a weekly dispatch of the Pacificorp portfolio for each of a series of (a) weekly draws of outages of Pacificorp generating units and (b) daily draws of Pacificorp loads. The model includes a proxy "ENS Station" station which is configured to "run" to meet loads after actual generation (including, as appropriate, energy delivered by FOTs) are exhausted, and to "turn off" otherwise. The reported generation of the ENS Station for each Monte Carlo iteration is therefore a measure of the total energy not served by the combination of Pacificorp generation and FOT energy. The number of starts reported for the ENS Station is then the number of episodes when FOT resources are insufficient to meet loads. The number of hours of operation of the ENS Station is the number of hours when FOT resources are insufficient to meet loads.

The configuration of the model to represent stochastic loads is described in more detail in section 1.2.4 above.

Generation outages are simulated through the comparison of each station's designated forced outage rate to a series of independent random draws, one per week per generating resource per Monte-Carlo iteration, where the random numbers are drawn from a uniform distribution of numbers between 0 and 1. If the drawn number for a station is less than its forced outage rate, then the station is removed from the portfolio for the week.

In most of the Monte-Carlo draws, and in most weeks, Pacificorp has more resources than are required to meet loads. Pacificorp, in common with most utilities, operates a portfolio that, in combination with expected market and emergency power access, contains sufficient resources to meet loads unless there are particularly adverse combinations of high loads and multiple simultaneous outages. A primary challenge in performing this sort of analysis is to perform enough draws of outages (in particular) to appropriately represent the frequency of the severe adverse combinations of station outages and high load draws. It is helpful to think of the probability distribution of several $MarginMW_{zt}$ variables for zone *z* and time *t,* computed as the zone's available resources (including the lesser of the neighboring zone's margin and transmission into *z*), minus the zone's loads. The reliability analysis involves various measurements on the left-hand, negative, tail of this distribution, including in particular the frequency of draws in the tail, which produces loss of load hours and probability, and the frequency-weighted area of the tail, which produces expected unserved energy. To make reasonable estimates of any of these measures requires sufficient draws to adequately represent the tail. In a reasonably reliable system these tail events are rare, and it therefore requires many more draws to get a decent measurement.

To find an appropriate number of Monte-Carlo draws a fast-running highly simplified model was created. The model made all resources must-run, and eliminated chronological constraints (minimum up and down time, ramp rates and start costs were set to zero, and the model was set to run only across the summer peak, at a 16% reserve margin. The model used the simplified Reliability-Model topology, summarized in the next section, and was run using different numbers of draws. It was found that the Expected Unserved Energy measure (the generation of the proxy ENS Stations) changed from run to run when less than 500 draws were performed, but that there was no large difference at higher numbers of draws. We therefore used 500 draws for the subsequent reliability simulations.

3.2 Reliability-Model Topology

In preliminary simulations with the full Pacificorp planning topology, represented by the detailed bubble-and-pipe diagram in Figure 2 above, unserved energy appeared almost entirely in the Utah North zone, with a few instances in Goshen and in Yakima. The Pacificorp transmission system is quite robust within the large blue-shaded regions in the diagram. We therefore rolled up the transmission areas within those regions for the purposes of reliability measurement. While this reliability-model topology is not suitable for production-cost analysis, as it would allow more within-region transmission of less expensive generation and reduce the use of high-cost peaking resources below what would be expected, it does not materially change the incidence and magnitude of simulated loss-of-load events, while making feasible the high number of Monte-Carlo draws that is necessary for reasonably precise estimation of the tails of the $MarginMW_{zt}$ distribution discussed in the previous section.

3.3 NWPP Reserve Pool Arrangements

Pacificorp's participation in the Northwest Power Pool (NWPP) reserve-pool arrangements allow it to receive energy from other participants in the pool for the first hour after a resource outage that would cause a loss of load event. The use of Proxy ENS stations allows simulation of the operation of the pool arrangements. The Reliability Model reports the gross output of the ENS stations, which we designate *G.* In the absence of the reserve pool, the expected value of *G* would be the Expected Unserved Energy reliability measure. The number of starts *s* of the Proxy ENS stations is the expected number of episodes, from which the LOLP measure may be derived. Finally, the model reports the number of hours *h* of "operation" of the Proxy ENS stations, which in the absence of the Reserve Pool would be Loss of Load Hours (LOLH).

The impact of the Reserve Pool on LOLH is clear: we compute $h^* = h - s$. To compute the contribution of the pool to EUE, we assume that the outage energy is approximately equal across each episode, so that the hours covered by the pool have the same energy as the residual hours h^*. We can then compute the reserve-pool energy as $R = s/h\ G$, and net EUE as $N = G - R = (h-s)/h\ G = h^*/h\ G$.

3.4 Principal Results

This section reports the principal results of the Reliability Model simulations in section 3.4.1. These raw simulations produce a decrease in reliability when perfectly-reliable FOT are replaced, at the 16% reserve margin level, by an additional thermal station. In general the study is evaluating small magnitudes, so changes such as this can produce seemingly anomalous results. To take advantage of the substantial information within the simulation runs, we performed a series of regression-base post processes, which are described in section 3.4.2. Section 3.4.3 analyzes the contribution of the NWPP Reserve Pool to reliability.

3.4.1 Simulation Results

Table 2 shows the principal raw simulation results of the 11 Reliability-Model simulations, one for each of the reserve-margin expansion plans produced by the capacity expansion runs (see section 2), for reliability year 2014. Note that 2.4 Loss of Load Hours per year is equivalent to one day in ten years: using an hours-based reliability measure the Pacificorp system meets this traditional reliability measure at all reserve margins.

The reliability measures all increase (these are all measures of loss of load, so an increase indicates reduced reliability) between reserve margins 13 and 14 and, more significantly, between reserve margins 15 and 16. A number of factors may account for this, of which the most important is that, between reserve margins 15 and 16 SO adds a combined-cycle station, which has a forced outage rate, and reduces the amount of perfectly-reliable FOT. In addition, this station is in the Southern-Oregon/Northern-California zone, and may be unable to fully respond (due to transmission constraints) to

Table 2. Simulated Reliability and NWPP Reserve Pool Contributions at Reserve Margins 10%--20%

	G:	*h:*	*s:*	$R = \frac{s}{h} G$	*N=G-R*	$LOLH = h - s$
Reserve Margin: %	Gross EUE MWh	Expected Gross Loss of Load Hours	Expected Loss of Load Episodes	NWPP Reserve Pool GWh	Net EUE GWh	Expected Net Loss of Load Hours
10	208.4	1.05	0.25	49.61	158.77	0.80
11	279.2	1.26	0.27	59.83	219.38	0.99
12	221.3	1.06	0.23	48.02	173.28	0.83
13	147.0	0.77	0.18	34.35	112.60	0.59
14	183.4	0.87	0.19	40.04	143.32	0.68
15	117.7	0.65	0.15	27.16	90.54	0.50
16	193.5	0.97	0.22	43.90	149.64	0.75
17	188.0	0.94	0.22	44.00	143.99	0.72
18	152.7	0.74	0.16	33.01	119.65	0.58
19	98.6	0.53	0.11	20.47	78.16	0.42
20	59.6	0.34	0.08	14.02	45.56	0.26

adverse combinations of high loads and multiple station outages in the Northern Utah zone where most of the unserved-energy appears. Above all, this is an issue of changes in a tail measurement that are small in magnitude but large in relative terms. These sorts of noisy observations are found in real-world observations as well as in simulations. In order to draw useful information for such processes we can use regression techniques. This approach is developed in the next section.

3.4.2 Regression Post-Processing

Table 3 shows the principal results from the regressions of several reliability measures against the reserve margin. EUE and Duration-Based LOLP were estimated both with and without the NWPP Reserve Sharing estimates; the episode-based LOLP measure does not reflect these arrangements.

These are simple equations estimated over only 11 observations, so the R^2 goodness-of-fit statistics (which measure the percent of deviations of the reliability measure from their mean, across 11 observations, that are captured by the regression equation) are not particularly high. However, the *t*-statistics on *b1* (the Reserve-Margin coefficient) are all highly significant. Given the small samples, these are useful regression equations.

Table 3. Reliability Smoothing Regression Results

	Reliability = b0 + b1 RM				
	Expected Unserved Energy		Duration-Based LOLP		Episode-Based LOLP
	With Reserve Sharing	Without Reserve Sharing	With Reserve Sharing	Without Reserve Sharing	Without Reserve Sharing
	R	*G*	*h-s*	*h*	*s*
R^2	0.585	0.599	0.628	0.641	0.668
b0	389.219	502.515	0.7459	0.96415	5.23791
se(b0)	73.317	92.086	0.12333	0.15534	0.79850
t(b0)	5.309	5.457	6.048	6.207	6.56
b1	-0.110	-0.142	-0.000202	-0.000262	-0.00143
se(b1)	0.031	0.039	0.0000519	0.0000654	0.00034
t(b1)	-3.548	-3.641	-3.892	-4.006	-4.206

Table 4 shows the fitted values from the equations described in Table 3, next to the simulated results from which the regression equations were computed. The linear reliability curves for each of the three reliability measure are then plotted in Figure 3, Figure 4, and Figure 5. Figure 3 highlights how the regression equation smooths the anomalous discontinuity after the addition of a thermal station at Reserve Margin 16.

Table 4. Simulated and Fitted Reliability, Reserve Margins 10%--20%

	With NWPP Reserve Sharing				Without NWPP Reserve Sharing				Without NWPP Reserve Sharing	
RM	EUE		LOLP Duration		EUE		LOLP Duration Based		LOLP Episode Based	
%	Simulated	Fitted	Simulated	Fitted	Simulated	Fitted	Simulated	Fitted	Simulated	Fitted
10	159	186.0196	0.33333	0.371968	208	239.9342	0.43750	0.480111	2.50000	2.595443
11	219	174.9054	0.41250	0.351515	279	225.5721	0.52500	0.453637	2.70000	2.450911
12	173	163.7890	0.34583	0.331059	221	211.2071	0.44167	0.427157	2.30000	2.30635
13	113	152.6759	0.24583	0.310608	147	196.8464	0.32083	0.400684	1.80000	2.161832
14	143	141.5607	0.28333	0.290153	183	182.4829	0.36250	0.374207	1.90000	2.017285
15	91	130.4454	0.20833	0.269699	118	168.1193	0.27083	0.347729	1.50000	1.872739
16	150	119.3301	0.31250	0.249244	194	153.7558	0.40417	0.321252	2.20000	1.728193
17	144	108.2148	0.30000	0.228789	188	139.3923	0.39167	0.294775	2.20000	1.583646
18	120	97.0985	0.24167	0.208333	153	125.0273	0.30833	0.268294	1.60000	1.439085
19	78	85.9832	0.17500	0.187878	99	110.6638	0.22083	0.241817	1.10000	1.294539
20	46	74.8668	0.10833	0.167421	60	96.29883	0.14167	0.215337	0.80000	1.149978

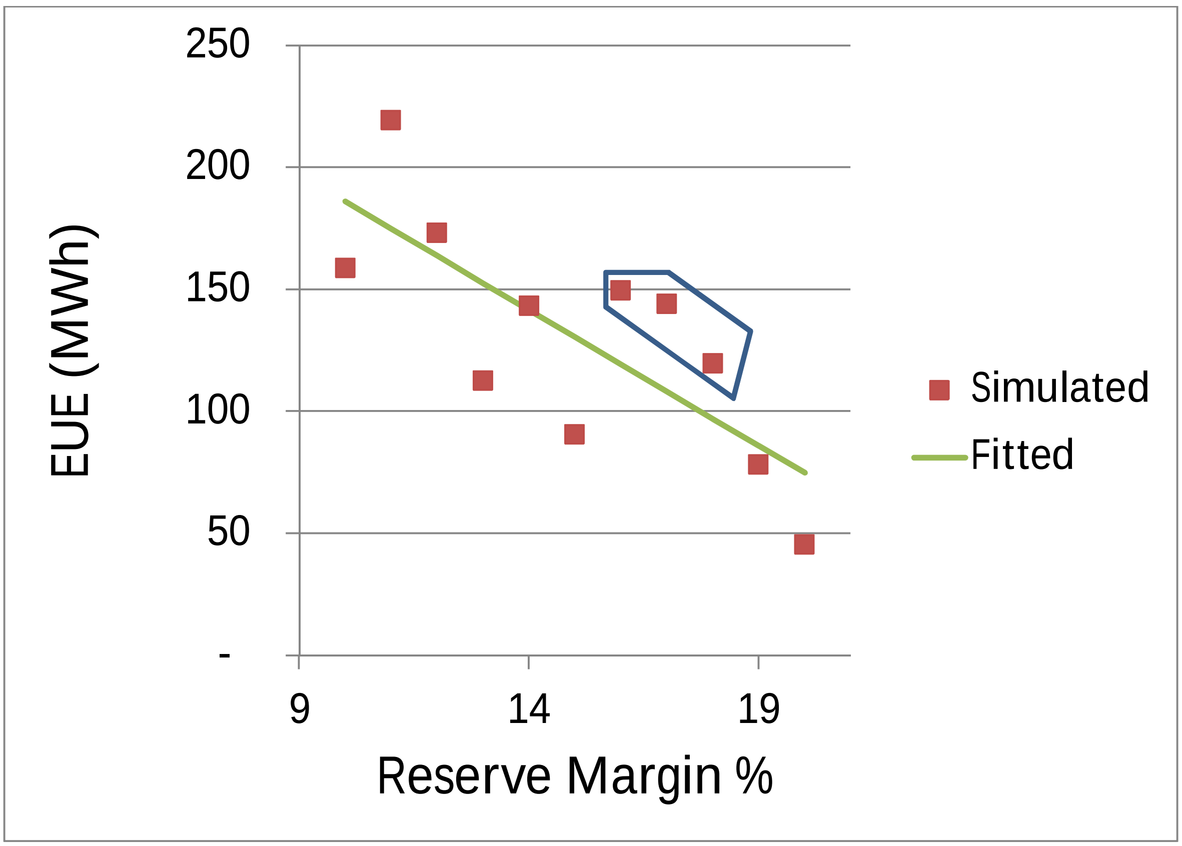

Figure 3. Simulated and Fitted Relationship of EUE to Reserve Margins

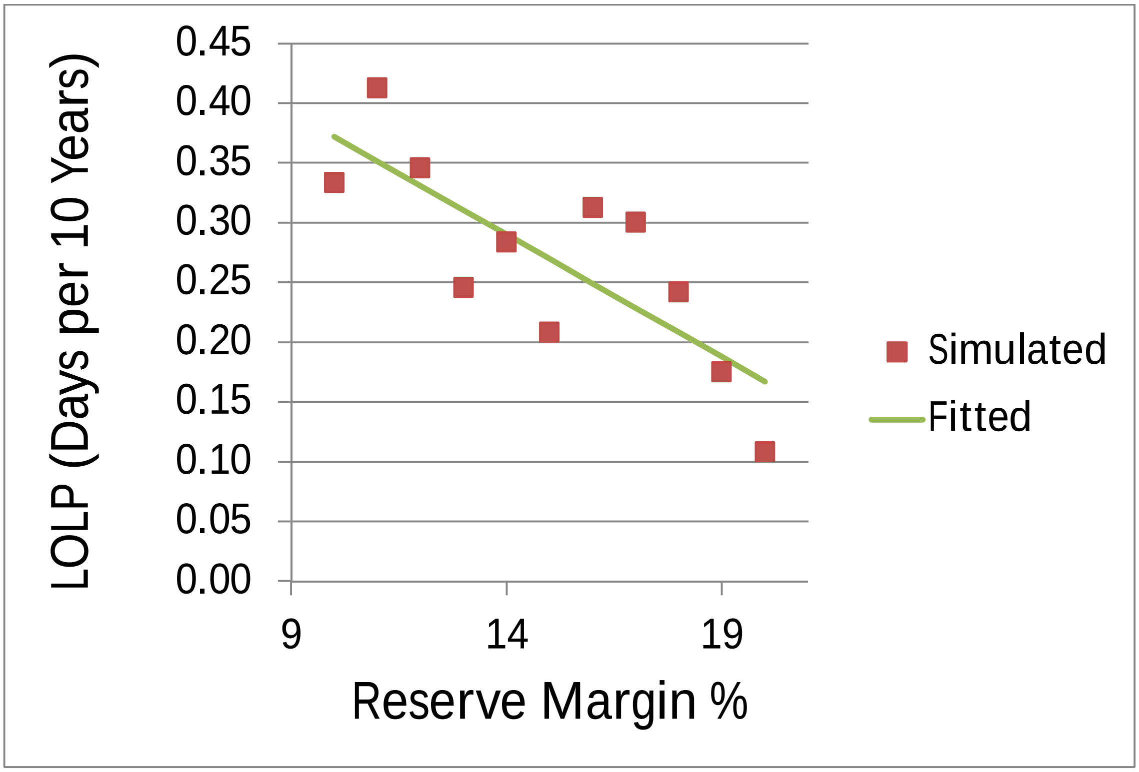

Figure 4. Simulated and Fitted Relationship of Duration-Based LOLP to Reserve Margins

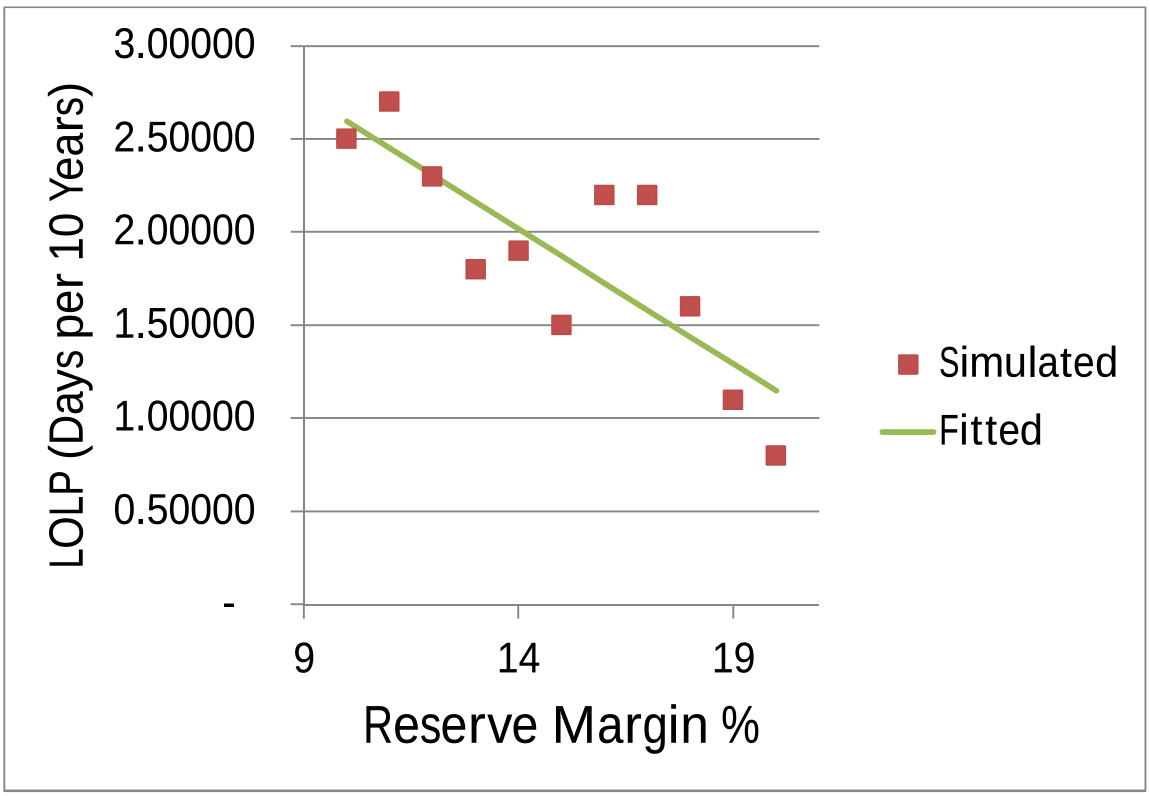

Figure 5. Simulated and Fitted Relationship of Episode-Based LOLP to Reserve Margins

3.4.3 Contribution of Reserve Pool to Reliability

The comparison of the regression equations with and without NWPP Reserve Sharing allows analysis of the reliability contributions of the Reserve Pool. It should be noted that this is only part of the benefit to Pacificorp of the Pool. Reliable operations generally involve maintaining contingency reserves based on the larger of a percentage of load (adjusted for the thermal/hydro mix of the system) and the largest single contingency; the reserve pool arrangement allows the largest-contingency requirement to be shared across multiple members, with each member's share of this requirement less than its own largest contingency. The evaluation here does not include the cost savings associated with carrying lower levels of reserves. Such an evaluation is a straightforward production-cost modeling exercise. Here we are concerned only with identifying the reduction in reserve margins that, holding reliability constant, is possible given participation in the reserve pool. To illustrate the effect, find the EUE measure at Reserve Margin 13% with Reserve Sharing, which from Table 4 is about 152.7 MWh. Comparing to the value without Reserve Sharing, this is a bit more than the 153.8 MWh produced by a 16% reserve margin. It is straightforward to calculate that a 16.1% Reserve Margin in the absence of reserve sharing would produce the same level of reliability as a 13% Reserve Margin: the Pool gives the same reliability benefits as a 3.1% increase in the reserve margin. Similar computations comparing the duration-based LOLP measures produce a 3.4% reserve-margin equivalence.

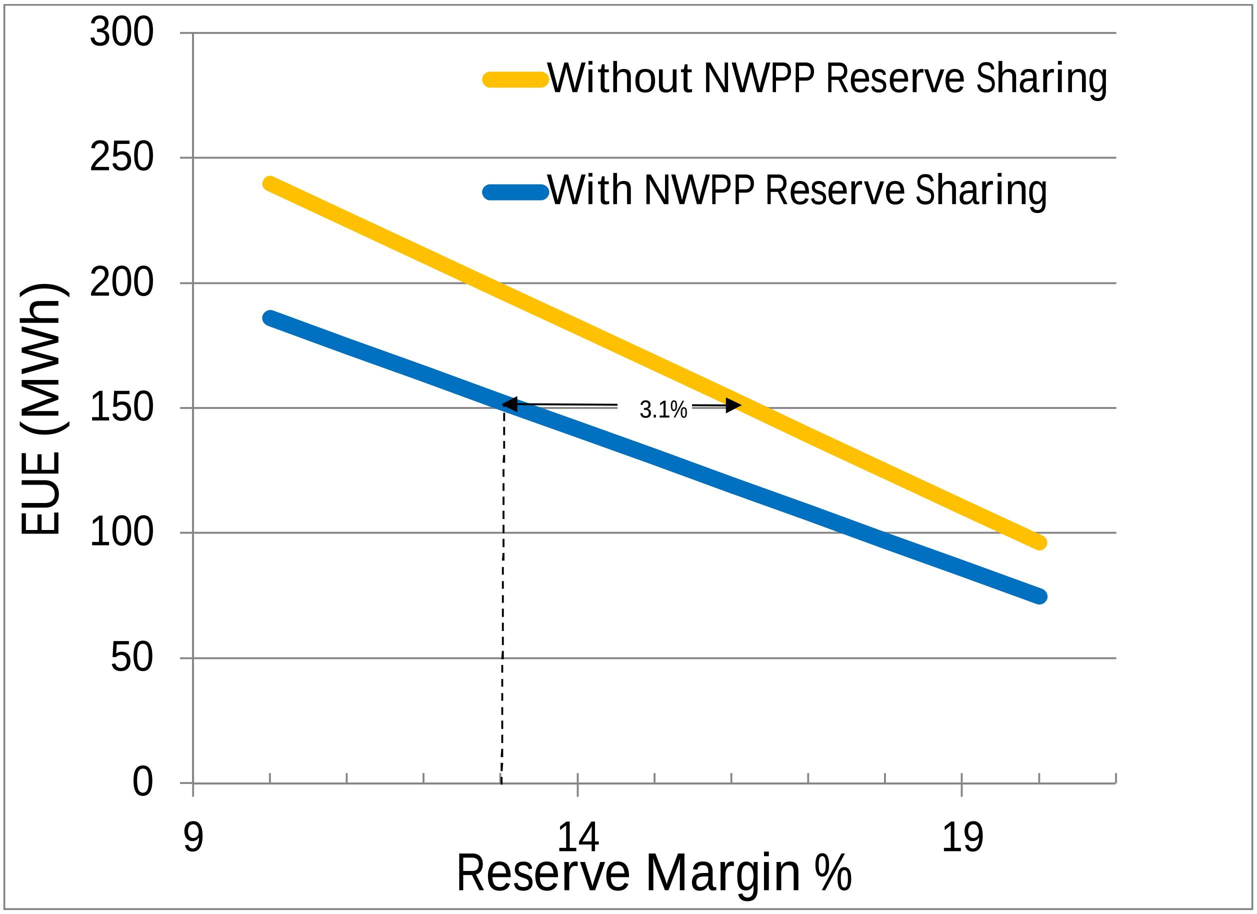

Figure 6. Reliability With and Without Reserve-Pool Arrangements

4 PRODUCTION COST MODEL

Table 5 reports the single-year capital costs and expected production costs of operating the portfolios in 2014 produced by the expansion plans summarized in Table 1 above. The expected production costs is from a stochastic production cost model that, in addition to the plant outage and hydro and load stochastics used for the reliability model, include stochastic natural gas and power prices. This is the same stochastic configuration used elsewhere in Pacificorp's resource planning activities. The model also inherits the market access assumptions that Pacificorp uses elsewhere, allowing, in particular, substantial economy market purchases which are excluded from the Reliability Model, while at the same time not assuming any emergency-power deliveries associated with the NWPP reserve-sharing arrangements, since those are not substitutes for expected commercial transactions.

It is worth noting that, except for the interval from 15 to 16 %, production costs steadily increase as the Reserve Margin increases due to the increased purchases of FOTs which are, by construction, out of the market. The production-cost curve shifts down at 16% when FOT purchases fall to accommodate the additional Southern-Oregon/Northern-California CCGT; this decrease is more than outweighed by the increase in capital costs associated with that station

Table 5. Capital and Production Costs at Different Planning Reserve Margins, 11%-18%

Reserve Margin	Production Cost	Station Capital Costs	Total
%	$ '000		
11	640,918	84,370	725,288
12	644,747	84,370	729,117
13	650,186	84,370	734,556
14	654,651	84,370	739,021
15	660,530	84,370	744,900
16	639,891	136,720	776,611
17	643,345	136,720	780,065
18	761,961	136,720	898,681

5 ANALYSIS

The combination of reliability results from different reserve margins, from section 3.4.2, and of the costs of acquiring and operation those reserve margins, from section 4, provides a basis for a recommendation regarding the reserve margin level. Table 6 contains all the elements necessary to compute both the full additional costs of moving from one reserve margin to the next, and the per-MWh cost of saved unserved energy. Figure 7 shows the per-MWh incremental cost in graphical form; this can be understood as a supply curve for reliability.

Table 6. Incremental Cost of Reliability, Reserve Margins 12-17%

MWAdded	Reserve Margin	Expected Unserved Energy (fitted) With NWPP Reserve Pool	Expected Unserved Energy (fitted) Without NWPP Reserve Pool	Expected Total Cost With NWPP Reserve Pool	Expected Incremental Cost	Incremental Cost of Reliability With NWPP Reserve Pool	Incremental Cost of Reliability Without NWPP Reserve Pool
	(percent)	(MWh)	(MWh)	($ '000)	($ '000)	($/MWh EUE)	($/MWh EUE)
2,051	12	164	211	729,117	3,828	344	267
2,152	13	153	197	734,556	5,439	489	379
2,253	14	142	182	739,021	4,466	402	311
2,355	15	130	168	744,900	5,879	529	409
2,456	16	119	154	776,611	31,711	2,853	2,208
2,557	17	108	139	780,065	3,455	311	241

The latter information provides, in principal, a strong basis of a reserve-margin recommendation. If we knew the value to consumers of incremental reliability (which is strongly related to the willingness of loads to voluntarily curtail), or some other form of a demand curve for energy, then we could select the reserve margin level where this reliability supply curve crosses a reliability demand curve.

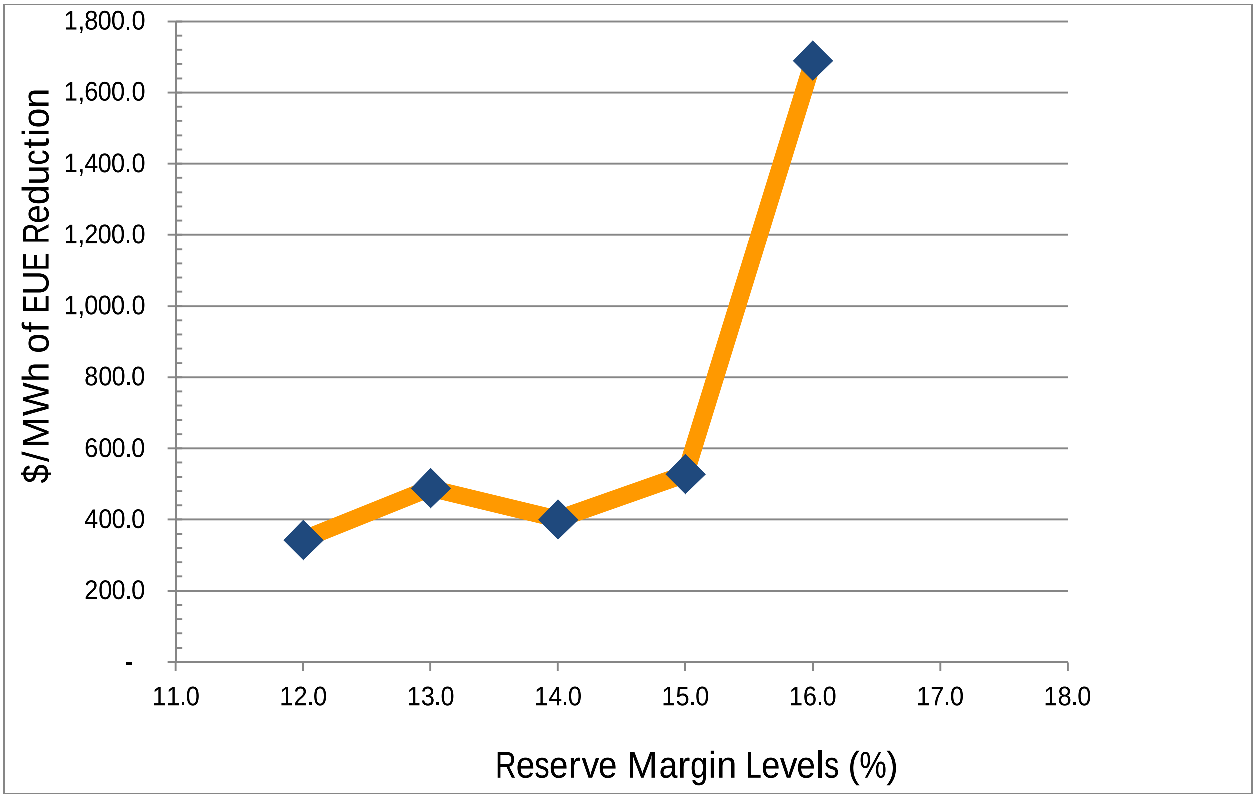

Figure 7. Incremental Cost of Reliability

Such information is not now available. However, as DSM programs are developed, such information will also become available for this sort of analysis, both directly in the case of price-strike dispatchable load reductions, and indirectly through analysis of the costs required to produce other voluntary load reductions.

In the absence of strong information about the incremental value to load of reliability, one cannot make a strong recommendation for a single point solution to the reserve-margin selection problem. However, there is one very strong conclusion from this analysis: increasing the Reserve Margin to 16% involves a substantial increase in cost (as it calls into the plan an additional thermal station), while producing only a moderate gain in reliability. Lacking strong evidence that there is little ability of loads to curtail at prices less than $1000/MWh, we cannot recommend an increase in reserve margins to this level. This is seen in the diagram as the sharp upward jump in the curve in Figure 7, from values in the $400/MWh range that are not inconsistent with the energy prices around the West during the California crisis, to values over three times as high. We cannot recommend a move into that reserve-margin region without serious investigation of other options. In particular, one would want to be sure that at prices above $1,000/MWh there weren't additional demand responses available.

The incremental cost of reliability at lower reserve margins do not differ significantly, making it impossible (even in the presence of information about the value to loads of reliability) to select among the 12%, 13%, 14% and 15% reserve-margin levels. It is important to recognize, however, that across the range of reserve margin levels increasing reserve margin levels are associated with increasing reliability. While the costs of those margins are not changing consistently, their impacts are, and their reliability impacts are felt primarily in a single area, the Utah-North zone. To reduce reserve margins from their current 13% level would be to impose a reliability cost upon loads in that region, while saving the entire system less that 1% of total expected cost. Conversely, we note that Pacificorp is engaged in the reinforcement of transmission into the Utah North zone, which will directly improve reliability in that region, without requiring an increase in reserve margins. The efficiency of transmission reinforcements in improving reliability in that zone, the disparate impact of reductions in the reserve margins below 13%, and the lack of a strong contrary measure of incremental cost of reliability combine to support a finding that it is reasonable for Pacificorp to retain its current practice, and continue to plan to a 13% Reserve Margin level. This is our recommendation.

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APPENDIX J – 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.*[58]

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 in the 2011 IRP, the Company conducted 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 H from the 2011 IRP describes the study methodology and presents results of the stochastic simulations.

Western Electricity Coordinating Council Resource Adequacy Assessment

The Western Electricity Coordinating Council (WECC) 2012 Power Supply Assessment (PSA) shows a planning reserve margin (PRM, as a percentage) calculated as a percentage of resources (generation and transfers) and load, and is the percentage of capacity above demand. The PRM indicates sufficient resources when the PRM is equal to or greater than the target reserve margin. The 2012 PSA shows WECC needing additional resources in 2020 (see Figure 2). Prior to the 2012 PSA report, WECC instead calculated a power supply margin (PSM, in MW amount) measuring ability to meet load requirement with resources and transfers. Since 2007, each subsequent PSA study defers resource need to later years. This deferment is a function of net

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

changes to: load growth expectations, class I capacity entrants, scheduled retirements, resource performance, transfer capabilities and modeling convention.[59]

In WECC Power Supply Assessments, the region and subregion target reserve margins are calculated using a building block methodology created by WECC. As such, they do not reflect a criteria-based margin determination process and do not reflect any balancing authority or load serving entity level requirements that may have been established through other processes (e.g., state regulatory authorities). They are not intended to supplant any of those requirements.

The building block methodology is comprised of four elements:

1. Contingency Reserves – An additional amount of operating reserves sufficient to reduce area control error to zero following loss of generating capacity, which would result from the most severe single contingency.

2. Regulating Reserves – The amount of spinning reserves responsive to automatic generation control that is sufficient to provide normal regulating margin. The regulating component of this guideline was calculated using data provided in WECC's annual loads and resources data request responses.

3. Additional Forced Outages – Reserves for additional forced outages beyond what might be covered by operating reserves in order to cover second contingencies are calculated using the forced outage data supplied to WECC through the loads and resources data request responses. Ten years of data are averaged to calculate both a summer (July) and winter (December) forced outage rate. The same forced outage rate is used for all balancing authorities in WECC when calculating the building block margin.

4. Temperature Adders – Using historic temperature data for up to 20 years, the annual maximum and minimum temperature for each balancing authority's area was identified. That data was used to calculate the average maximum (summer) and minimum (winter) temperature and the associated standard deviation.

As seen in Figure J.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 2007 through 2009 are comparable, the 2010 PSA employed a different, and superior, modeling convention. Namely, PROMOD IV, a chronological production cost model, was used beginning with the 2010 PSA to assess WECC resource adequacy[60]. PROMOD IV, unlike WECC's previous model, uses coincident peak demand and employs a more robust optimization of sub-regional transfers.

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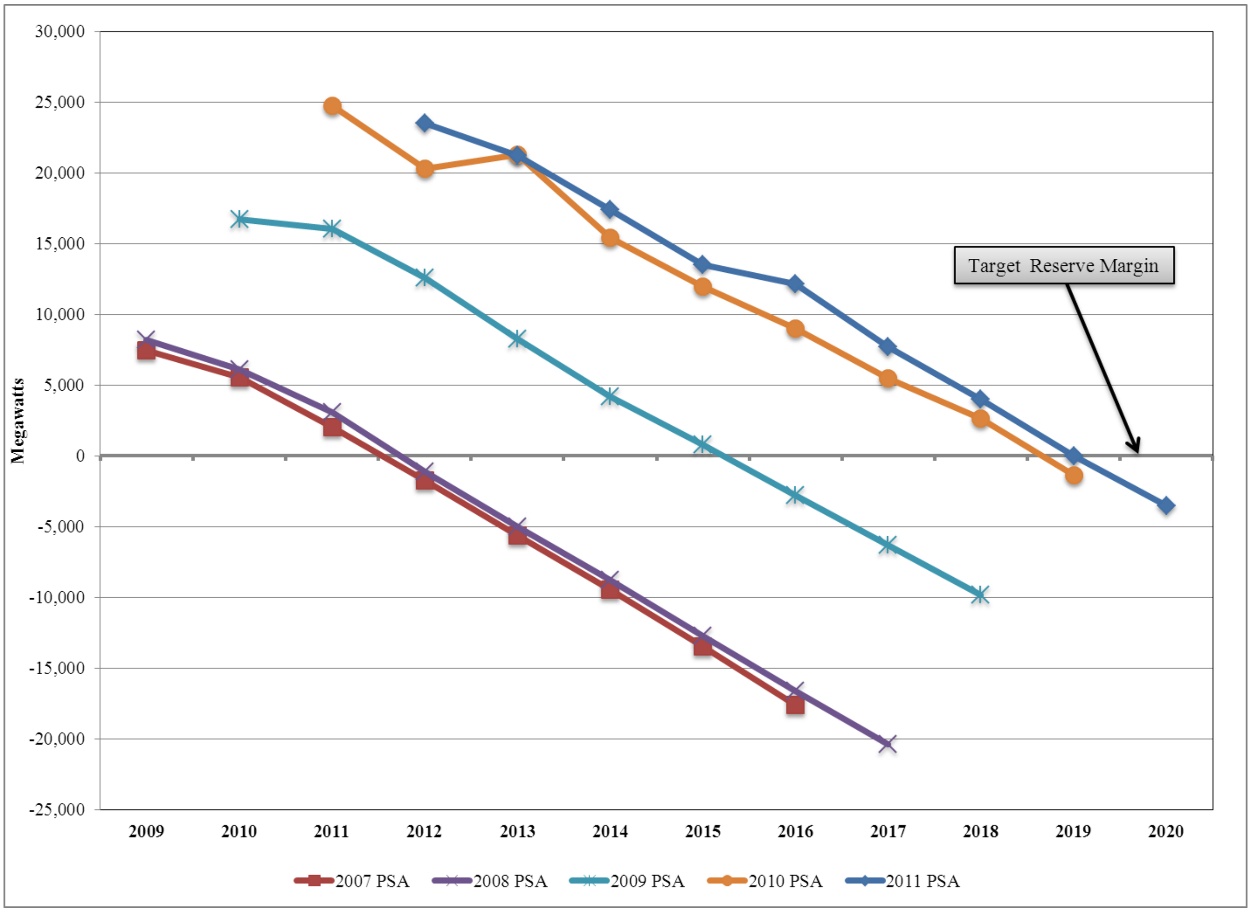
[59] The 2012 PSA defines Class I as existing generation that is available (in-service) as of December 31, 2011, and net generation additions/retirements that were reported to be under active construction as of December 31, 2011 and are projected to be in-service/retired prior to January 2017. The 2011, 2010, 2009 and 2008 PSA defined Class I to included generation online by 2016, 2014, 2013, and 2012, respectively.

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

Figure J.1 – WECC Forecasted Power Supply Margins, 2007 to 2011



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

Figure J.2 shows the planning reserve margin calculated in the 2012 WECC Power Supply Assessment report. The 2012 WECC power reserve margin results show that there is not a resource need until 2020, which compares to the 2011 assessment which projects a resource need in 2019.

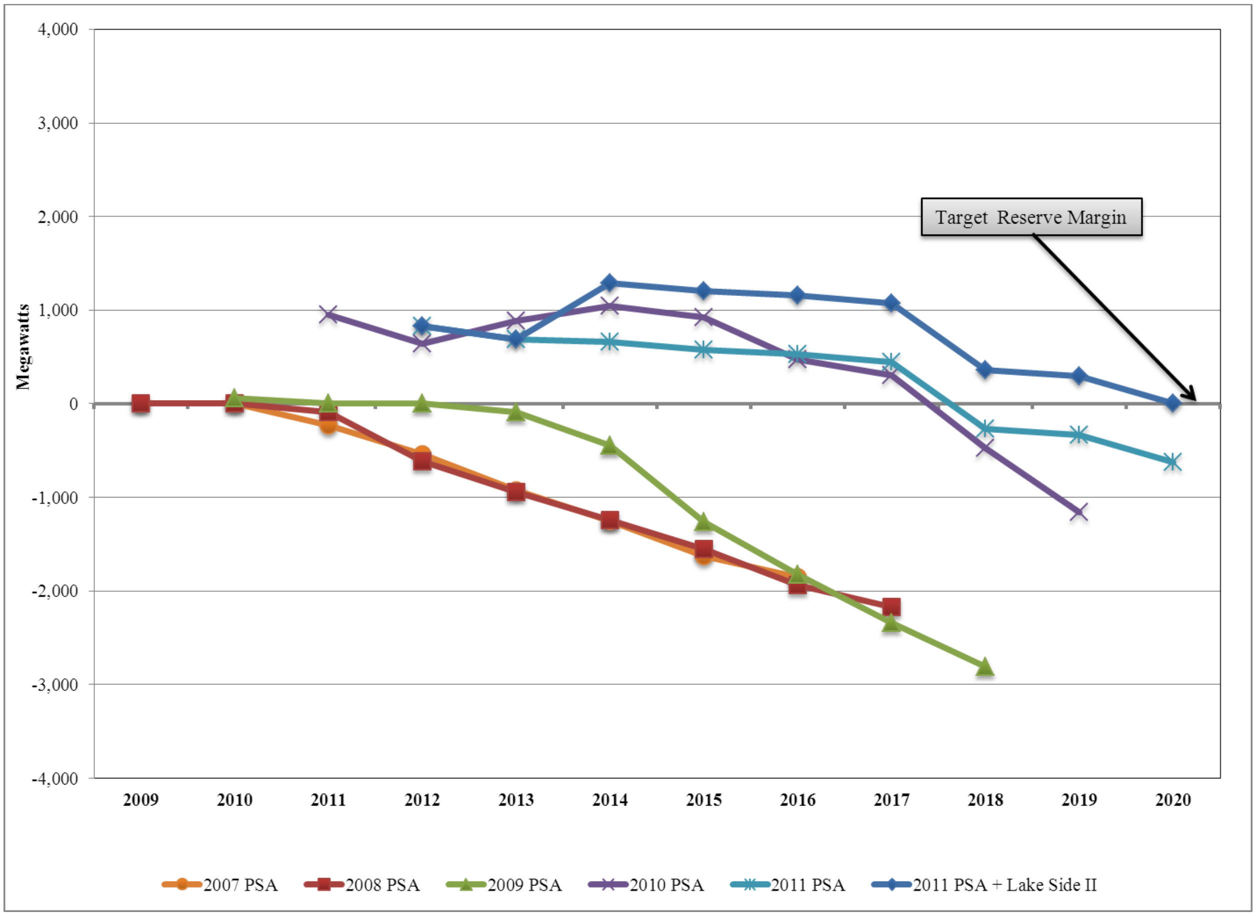
Figure J.2 – 2012 WECC Forecasted Planning Reserve Margins

Planning Reserve Margin		Summer; Existing and Class 1 Resources									
Subregion	Target Reserve Margin	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Northwest	**17.9%**	20.4%	19.5%	20.5%	24.2%	21.1%	19.3%	19.4%	19.5%	19.5%	19.7%
Basin	**12.6%**	32.0%	32.5%	29.9%	25.6%	24.7%	20.9%	17.2%	16.2%	14.5%	16.6%
Rockies	**14.7%**	27.8%	25.7%	21.5%	19.3%	17.4%	15.6%	17.0%	17.1%	16.1%	15.2%
Desert Southwest	**13.5%**	45.0%	40.9%	42.8%	44.7%	40.6%	40.7%	36.5%	29.8%	26.4%	26.0%
WECC Total	**14.6%**	25.4%	23.2%	22.1%	19.3%	17.4%	15.7%	15.1%	13.3%	11.5%	9.3%

Note: 2012 WECC Power Supply Assessment, including Class 1 Planned Resources Only

Basin is a summer peaking WECC subregion comprised of Utah, Idaho, and northern Nevada. A review of PSA studies from 2007 through 2011 reveals a similar pattern to that of WECC for the same period. The 2011 WECC Power Supply Assessment shows a resource need in 2018. When including the addition of the Company's Lake Side 2 resource, this resource need would be deferred to 2020. As seen in Figure J.3, the target reserve margin is maintained at the "zero" horizontal axis. 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.

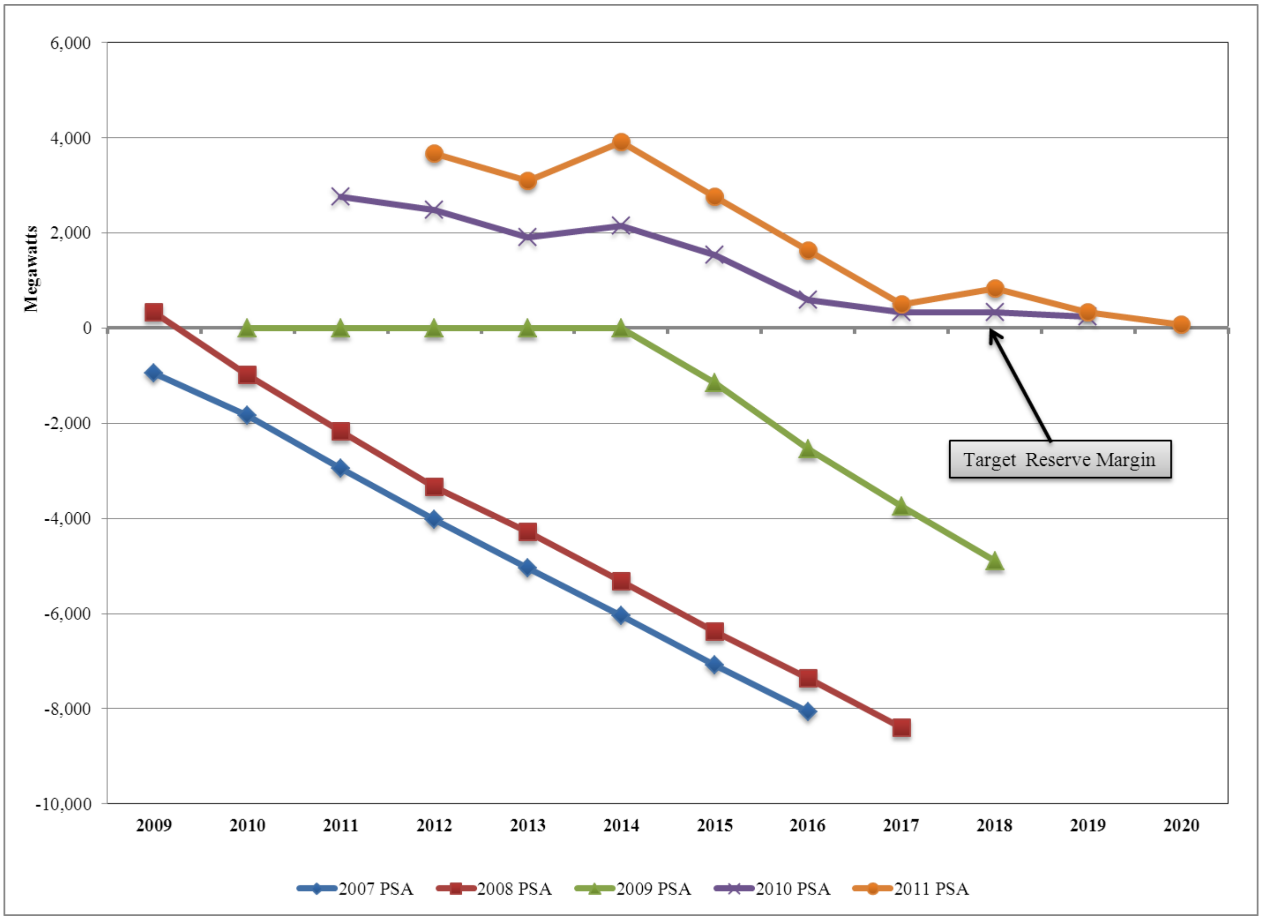
Figure J.3 – Basin Forecasted Power Supply Margins



Note: WECC Power Supply Assessments include Class 1 Planned Resources Only. Lake Side 2 is currently under construction but was not included in the 2011 Power Supply Assessment for Class 1 resources. The chart above shows the 2011 power supply margin with and without Lake Side 2. The 2012 Power Supply Assessment also does not include Lake Side 2 for Class 1, since it was not under construction in time to meet definition of Class 1 for the 2012 WECC report.

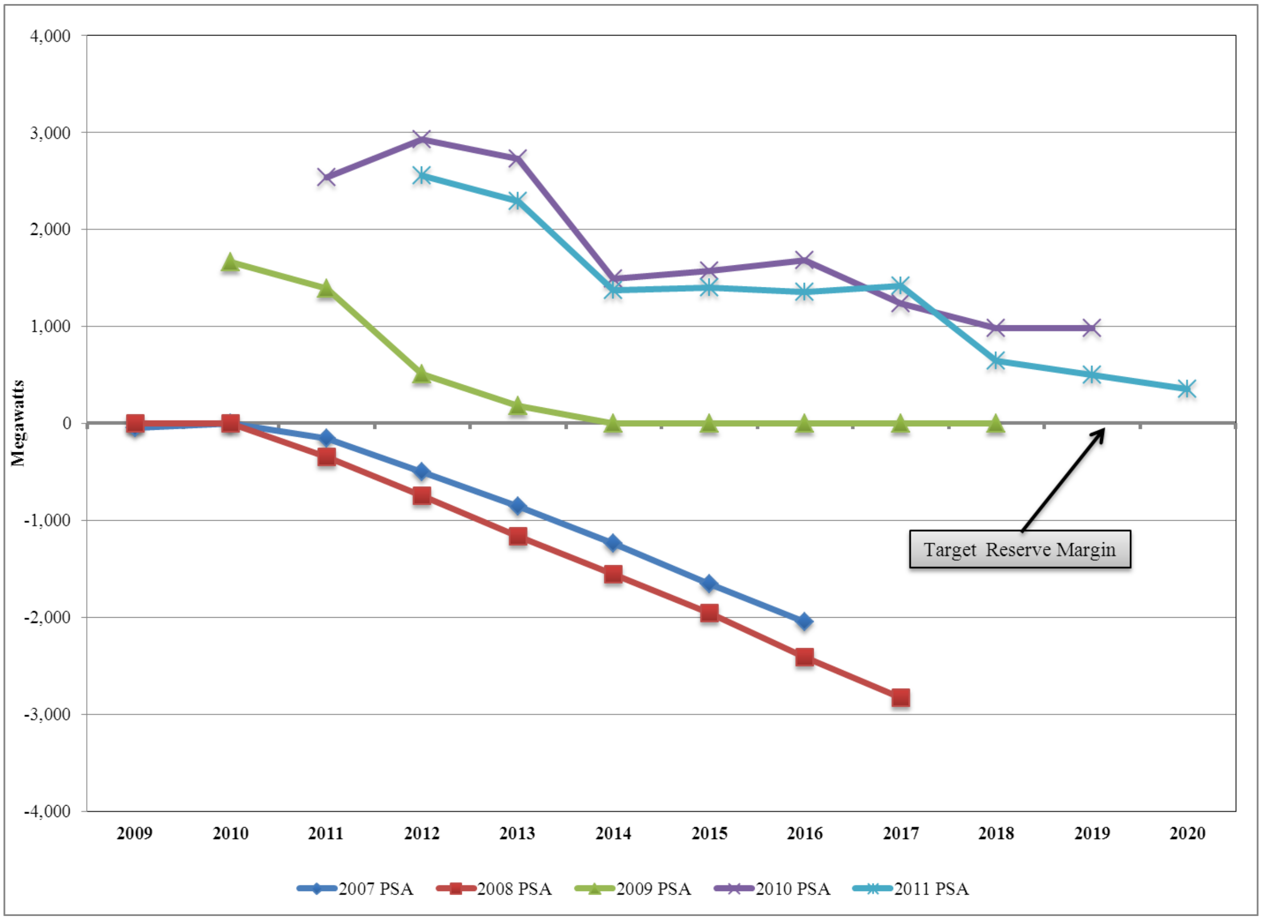
Consistent with the planning reserve margins calculated for Rockies (Colorado and Wyoming) and Desert Southwest (Arizona, New Mexico and southern Nevada) subregions in the 2012 WECC Power Supply Assessment, Figures J.4 and J.5, showing the 2011 WECC report results, also show resource deferment until 2020 for the Desert Southwest subregion and after 2020 for the Rockies subregion.

Figure J.4 – Desert Southwest Forecasted Power Supply Margins



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

Figure J.5 – Rockies Forecasted Power Supply Margins



Note: WECC Power Supply Assessments include 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[61] 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 2012 PSA, WECC maintains a positive PSM through 2019. The Basin, Desert Southwest, Northwest[62], and Rockies subregions are forecasted to maintain sufficient planning reserve margins through 2022. 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.

[61] Market liquidity refers to having ready and willing buyers and sellers for large transactions.
[62] The Northwest is comprised of the Pacific Northwest and Montana.

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. In a November 2012 report, the Forum concluded that the likelihood of a shortfall between the region's power supply and forecasted load growth in 5 years out had increased from 5 percent to 6.6 percent.[63] This means that the region will have to acquire additional resources in order to maintain an adequate power supply, a finding that supports acquisition actions currently being taken by regional utilities. Between 2015 and 2017, the region's electricity loads, net of planned energy efficiency savings, are expected to grow by about 300 average megawatts or about a 0.7 percent annual rate. Since the last assessment, 114 megawatts of new thermal capacity and about 1,200 megawatts of new wind capacity have been added along with about 250 megawatts of small hydro and hydro upgrades.

The majority of potential future issues are short-term capacity shortfalls. The most critical months are January and February and, to a lesser extent, August. This is a different result from the 2015 assessment, which indicated that August was the most critical month. The major reason for this shift is the use of an updated stream flow record, which contains 10 more years of historical flows, new irrigation withdrawal amounts and various updates to reservoir operations both in the U.S. and Canada. The net result yields a higher average stream flow in August, thus improving summer adequacy.

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.

[63] Pacific Northwest Power Supply Adequacy Assessment for 2017, at http://www.nwcouncil.org/media/30104/2012_12.pdf

APPENDIX K – DETAILED CAPACITY EXPANSION RESULTS

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. There are 19 core cases, and each was run under the five Energy Gateway scenarios. One exception is that Case C-19, on alternative to Segment D of the Energy Gateway, is not applicable to EG1 that does not include segment D, so there is no study required.

Table K.1 – Gateway Scenario Definitions

Scenario	Segments	Description
EG1	C, and G	**Reference** – Mona-Oquirrh-Terminal, Sigurd-Red Butte
EG2	C, D, and G	**System Improvement** – 2013 Business Plan
EG3	C, D, E, G, and H	**West/East Consolidation** – Increase interchange between PACE and PACW
EG4	C, D, G, and F	**Triangle** – East side wind and improved reliability
EG5	C, D, E, G, H, and F	**Full Gateway** – All Energy Gateway segments

Table K.2 – Core Case Definitions

Theme	Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Other
Reference	C01	Medium	Medium	Medium	None	Base	n/a
	C02	Medium	Medium	Medium	State	Base	n/a
	C03	Medium	Medium	Medium	State & Federal	Base	n/a
Environmental Policy	C04	Low	High	High	None	Base	n/a
	C05	Low	High	High	State & Federal	Base	n/a
	C06	High	Zero	Low	None	Base	n/a
	C07	High	Zero	Low	State & Federal	Base	n/a
	C08	Low	High	High	None	Base	n/a
	C09	Low	High	High	State & Federal	Base	n/a
	C10	Medium	Medium	Medium	None	Base	n/a
	C11	Medium	Medium	Medium	State & Federal	Base	n/a
	C12	High	Zero	Low	None	Base	n/a
	C13	High	Zero	Low	State & Federal	Base	n/a
	C14	Medium	Hard Cap (Medium Gas)	Medium	State & Federal	Accelerated	n/a
Targeted Resources	C15	Medium	Medium	Medium	State & Federal	Accelerated	No CCCT
	C16	Medium	Medium	Medium	State & Federal	Base	Geothermal/RPS
	C17	High	Medium	Medium	State & Federal	Base	Market Spike
	C18	Medium	Hard Cap (High Gas)	Medium	None	Accelerated	Clean Energy
Transmission	C19	Medium	Medium	Medium	State & Federal	Base	Alt. to Segment D

Table K.3 – Sensitivity Case Definitions

Theme	Case #	Load	Gas Price	CO2 Price	RPS	PTC/ITC	Coal Investments
Load Sensitivity	S-01	Low	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-02	High	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-03	1 in 20	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Targeted	S-05	Base	Medium	Medium	None	2019/2019	Optimized
Resource	S-06	Base	Medium	Medium	State & Federal (RPS Floor)	2019/2019	Optimized
	S-07	Base	Medium	Medium	State & Federal (Optimized)	2012/2016	Optimized
	S-09	Base	High	High	State & Federal (RPS Floor)	2019/2019	Optimized
	S-10	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Environmental Policy	S-04 (Volume III)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Hypothetical Regional Haze
	S-X (Volume III)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Next Best Alternative

Notes

1. All sensitivity cases are based on Energy Gateway Scenario 2, consistent with the scenario in the 2013 IRP preferred portfolio.
2. Sensitivity Case S-07 applies state RPS targets as system targets in the System Optimizer model. All other sensitivities either use the RPS Scenario Maker to establish a renewable resource floor or exclude RPS requirements altogether.
3. Case S-08 (simulating PacifiCorp's 2013 Business Plan portfolio in the current input setup) was removed due to incompatibilities in how Class 2 DSM resources are modeled in the 2013 IRP.
4. Sensitivity cases S-04 (Hypothetical Regional Haze Compliance Alternative) and S-X (Emission Control PVRR(d) Analysis) are confidential and summarized in confidential Volume III of the 2013 IRP report.

Table K.4 – Resource Name and Description

Resource List	Detailed Description
East Resources	
CCCT F 2x1	Combine Cycle Combustion Turbine F-Machine 2x1 with Duct Firing
CCCT FD 1x1	Combine Cycle Combustion Turbine FD-Machine 1x1 with Duct Firing
CCCT FD 2x1	Combine Cycle Combustion Turbine FD-Machine 2x1 with Duct Firing
CCCT GH 1x1	Combine Cycle Combustion Turbine GH-Machine 1x1 with Duct Firing
CCCT GH 2x1	Combine Cycle Combustion Turbine GH-Machine 2x1 with Duct Firing
CCCT J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing
IC Aero UT	Inter-cooled Simple Cycle Combustion Turbine Aero - Utah
IC Aero WYAE	Inter-cooled Simple Cycle Combustion Turbine Aero - Wyoming
IC Aero WYNE	Inter-cooled Simple Cycle Combustion Turbine Aero - Wyoming
IC Aero WYSW	Inter-cooled Simple Cycle Combustion Turbine Aero - Wyoming
SCCT Aero UT	Simple Cycle Combustion Turbine Aero - Utah
SCCT Aero WYNE	Simple Cycle Combustion Turbine Aero - Wyoming
SCCT Frame ID	Simple Cycle Combustion Turbine Frame - Idaho
SCCT Frame UT	Simple Cycle Combustion Turbine Frame - Utah
SCCT Frame WYAE	Simple Cycle Combustion Turbine Frame - Wyoming
SCCT Frame WYNE	Simple Cycle Combustion Turbine Frame - Wyoming
SCCT Frame WYSW	Simple Cycle Combustion Turbine Frame - Wyoming
Lake Side II	Lake Side II
Nuclear	Nuclear
Geothermal, Greenfield	Geothermal, Greenfield
WY IGCC CCS	Integrated Gasification Combined Cycle with Carbon Capture & Sequestration - Wyoming
Coal Ret_UT - Gas RePower	Coal Plant conversion to Gas Plant - Utah (Cholla, Hunter, or Huntington)
Fly Wheel	Fly Wheel
CAES	Compressed Air Energy Storage
Battery Storage	Battery Storage
Pump Storage	Pump Storage
Utility Solar - PV	Utility Solar - Photovoltaic
Micro Solar - PV	Micro Solar - Photovoltaic
Micro Solar - Water Heating	Micro Solar - Water Heating
Wind, GO, 29	Wind, Goshen Idaho, 29% Capacity Factor
Wind, UT, 29	Wind, Utah, 29% Capacity Factor
Wind, WYAE, 40	Wind, Wyoming, 40% Capacity Factor
CHP - Biomass	Combined Heat and Power - Biomass

Resource List	Detailed Description
CHP - Reciprocating Engine	Combined Heat and Power - Reciprocating Engine
CHP - Other	Combined Heat and Power - Other
DSM, Class 1, ID-Curtail	DSM Class 1, Curtailment - Idaho
DSM, Class 1, ID-DLC-IRR	DSM Class 1, Direct Load Control-Irrigation - Idaho
DSM, Class 1, ID-DLC-RES	DSM Class 1, Direct Load Control-Residential - Idaho
DSM, Class 1, ID-Irrigate	DSM Class 1, Direct Load Control-Irrigation - Idaho
DSM, Class 1, UT-Curtail	DSM Class 1, Curtailment - Utah
DSM, Class 1, UT-DLC-RES	DSM Class 1, Direct Load Control-Residential - Utah
DSM, Class 1, UT-Irrigate	DSM Class 1, Direct Load Control-Irrigation - Utah
DSM, Class 1, WY-Curtail	DSM Class 1, Curtailment - Wyoming
DSM, Class 1, WY-DLC-RES	DSM Class 1, Direct Load Control-Residential - Wyoming
DSM, Class 1, WY-Irrigate	DSM Class 1, Direct Load Control-Irrigation - Wyoming
DSM, Class 3, UT-TOU-RES	DSM, Class 3, Time of Use, Residential - Utah
DSM, Class 3, WY-TOU-IRR	DSM, Class 3, Time of Use, Irrigation - Wyoming
DSM, Class 3, WY-TOU-RES	DSM, Class 3, Time of Use, Residential - Wyoming
DSM, Class 2, ID	DSM, Class 2, Idaho
DSM, Class 2, UT	DSM, Class 2, Utah
DSM, Class 2, WY	DSM, Class 2, Wyoming
FOT Mead Q3	Front Office Transaction - 3rd Quarter HLH Product - Mead
FOT Mona Q3	Front Office Transaction - 3rd Quarter HLH Product - Mona

Resource List	Detailed Description
West Resources	
CCCT F 2x1	Combine Cycle Combustion Turbine F-Machine 2x1 with Duct Firing
CCCT GH 1x1	Combine Cycle Combustion Turbine GH-Machine 1x1 with Duct Firing
CCCT GH 2x1	Combine Cycle Combustion Turbine GH-Machine 2x1 with Duct Firing
CCCT J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing
IC Aero WV	Inter-cooled Simple Cycle Combustion Turbine Aero - Willamette Valley
IC Aero WW	Inter-cooled Simple Cycle Combustion Turbine Aero - Walla Walla
IC Aero PO	Inter-cooled Simple Cycle Combustion Turbine Aero - Portland/North Coast
IC Aero SO-CAL	Inter-cooled Simple Cycle Combustion Turbine Aero - Southern Oregon/California
SCCT Aero PO	Simple Cycle Combustion Turbine Aero - Portland/North Coast
SCCT Aero WV	Simple Cycle Combustion Turbine Aero - Willamette Valley

Resource List	Detailed Description
SCCT Aero WW	Simple Cycle Combustion Turbine Aero - Walla Walla
SCCT Frame OR	Simple Cycle Combustion Turbine Frame - Oregon
SCCT Frame WW	Simple Cycle Combustion Turbine Frame - Walla Walla
Coal Ret_Bridger -Gas RePower	Coal Plant conversion to Gas Plant - Jim Bridger
Geothermal, Greenfield	Geothermal, Greenfield
Fly Wheel	Fly Wheel
Battery Storage	Battery Storage
Pump Storage	Pump Storage
Utility Solar - PV	Utility Solar - Photovoltaic
Micro Solar - PV	Micro Solar - Photovoltaic
Micro Solar - Water Heating	Micro Solar - Water Heating
OR Solar (Util Cap Standard & Cust Incentive Prgm)	OR Solar (Util Cap Standard & Cust Incentive Prgm)
Utility Biomass	Utility Biomass
Wind, HM, 29	Wind, Hemmingway, 29% Capacity Factor
Wind, WV, 29	Wind, Willamette Valley, 29% Capacity Factor
CHP - Biomass	Combined Heat and Power - Biomass
CHP - Reciprocating Engine	Combined Heat and Power - Reciprocating Engine
CHP - Other	Combined Heat and Power - Other
DSM, Class 1, CA-Curtail	DSM Class 1, Curtailment - California
DSM, Class 1, CA-DLC-IRR	DSM Class 1, Direct Load Control-Irrigation - California
DSM, Class 1, CA-DLC-RES	DSM Class 1, Direct Load Control-Residential - California
DSM, Class 1, OR-Curtail	DSM Class 1, Curtailment - Oregon
DSM, Class 1, OR-DLC-IRR	DSM Class 1, Direct Load Control-Irrigation - Oregon
DSM, Class 1, OR-DLC-RES	DSM Class 1, Direct Load Control-Residential - Oregon
DSM, Class 1, WA-Curtail	DSM Class 1, Curtailment - Washington
DSM, Class 1, WA-DLC-IRR	DSM Class 1, Direct Load Control-Irrigation - Washington
DSM, Class 1, WA-DLC-RES	DSM Class 1, Direct Load Control-Residential - Washington
DSM, Class 3, CA-TOU-IRR	DSM, Class 3, Time of Use, Irrigation - California
DSM, Class 3, CA-TOU-RES	DSM, Class 3, Time of Use, Residential - California
DSM, Class 3, OR-TOU-IRR	DSM, Class 3, Time of Use, Irrigation - Oregon
DSM, Class 3, OR-TOU-RES	DSM, Class 3, Time of Use, Residential - Oregon
DSM, Class 3, WA-TOU-IRR	DSM, Class 3, Time of Use, Irrigation - Washington
DSM, Class 3, WA-TOU-RES	DSM, Class 3, Time of Use, Residential - Washington
DSM, Class 2, CA	DSM, Class 2, California

Resource List	Detailed Description
DSM, Class 2, OR	DSM, Class 2, Oregon
DSM, Class 2, WA	DSM, Class 2, Washington
FOT COB Flat	Front Office Transaction - 3rd Quarter Flat Product - COB
FOT COB Q3	Front Office Transaction - 3rd Quarter HLH Product - COB
FOT Mid Columbia Flat	Front Office Transaction - 3rd Quarter Flat Product - Mid Columbia
FOT MidColumbia Q3	Front Office Transaction - 3rd Quarter HLH Product - Mid Columbia
FOT MidColumbia Q3 - 2	Front Office Transaction - 3rd Quarter HLH Product - Mid Columbia
FOT NOB Q3	Front Office Transaction - 3rd Quarter HLH Product - Nevada Oregon Border

Table K.5 – Core Case System Optimizer PVRR Results

PVRR for cases under EG2 to EG5 are adjusted for $655 System Operational and Reliability Benefits Tool (SBT) benefit of Segment D ($ millions)

	Study Name	EG-1	EG-2	EG-3	EG-4	EG-5
C-01	Base, No RPS	30,983	31,237	31,885	31,878	32,506
C-02	Base, State RPS	31,504	31,540	32,204	32,171	32,842
C-03	Base, State & Federal RPS	31,605	31,583	32,235	32,208	32,866
C-04	Base Regional Haze, Low Gas, High CO2 & Coal, No RPS	32,516	32,755	33,360	33,344	33,973
C-05	Base Regional Haze, Low Gas, High CO2 & Coal, With RPS	33,136	33,104	33,713	33,675	34,336
C-06	Base Regional Haze, High Gas, No CO2, Low Coal, No RPS	27,011	27,269	27,920	27,896	28,553
C-07	Base Regional Haze, High Gas, No CO2, Low Coal, With RPS	27,568	27,516	28,181	28,145	28,814
C-07a	**Preferred Portfolio**		**27,347**			
C-08	Stringent Regional Haze, Low Gas, High CO2 & Coal, No RPS	32,778	33,039	33,667	33,612	34,266
C-09	Stringent Regional Haze, Low Gas, High CO2 & Coal, With RPS	33,365	33,348	33,959	33,926	34,599
C-10	Stringent Regional Haze, Med Gas, Med CO2 & Coal, No RPS	31,533	31,772	32,459	32,419	33,075
C-11	Stringent Regional Haze, Med Gas, Med CO2 & Coal, With RPS	32,138	32,135	32,760	32,748	33,410
C-12	Stringent Regional Haze, High Gas, No CO2, Low Coal, No RPS	27,563	27,818	28,469	28,450	29,095
C-13	Stringent Regional Haze, High Gas, No CO2, Low Coal, With RPS	28,121	28,073	28,730	28,699	29,370
C-14	Base Regional Haze, Med Gas, U.S. Hard Cap, Med Coal, With RPS	43,141	43,114	43,626	43,653	44,146
C-15	No Thermal Base Load	31,425	31,394	32,050	32,016	32,688
C-16	Geothermal RPS Strategy	31,581	31,644	32,304	32,274	32,937
C-17	Market Price Spike	31,519	31,488	32,239	32,199	32,867
C-18	Clean Energy Bookend	48,406	48,173	48,358	48,563	48,799
C-19	Energy Gateway Segment D Alternative	N/A	31,589	32,281	32,242	32,900

Table K.6 – Sensitivity Case – EG2 System Optimizer PVRR Results

PVRR are adjusted for $655 SBT benefit for Segment D ($ millions)

	Study Name	EG-2
S-01	Low Load Forecast	30,656
S-02	High Load Forecast	33,129
S-03	1 in 20 Load	31,978
S-05	PTC/ITC Ext. (No RPS)	31,237
S-06	PTC/ITC Ext. (With RPS)	31,485
S-07	Endogenous RPS Comp.	31,603
S-09	Targeted Renewables	38,996
S-10	Class 3 DSM	31,586

The next section of Appendix K provides the detail portfolio tables for each of the System Optimizer Case studies and are divided into the following sections:

Table K.7 – Energy Gateway Scenario 1 – Case C-01 to C-18
Table K.8 – Energy Gateway Scenario 2 – Case C-01 to C-19
Table K.9 – Energy Gateway Scenario 3 – Case C-01 to C-19
Table K.10 – Energy Gateway Scenario 4 – Case C-01 to C-19
Table K.11 – Energy Gateway Scenario 5 – Case C-01 to C-19
Table K.12 – Sensitivity Cases under Energy Gateway Scenario 2, excluding S-04 and S-X that are included in Confidential Volume III

Note: Front office transaction amounts reported in the portfolios reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.7 – Energy Gateway Scenario 1 – Case C-01 to C-18

EG-1 Case C-01		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	3
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	3
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	7	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	7	-	4	-	15
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	9	-	-	-	6	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	-	-	-	10	106	-	7	-	18	-	142
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	30	581	937
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	170	263	141	106	221	299	300	40	148	198	299	65	133
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	7	44	1	-	-	-	4	-	55
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	21	23	22	22	22	22	22	22	22	22	23	282	504
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	28	28	27	27	27	28	26	26	26	26	27	360	627
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	83	297	297	297	182	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	100	95	96	96	85	266	743	88	135	924	736	504	74	96		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,342	1,435	1,313	1,278	1,393	1,471	1,472	998	1,320	1,370	1,471		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,431	1,523	1,295	1,438	1,520	1,579	2,021	1,481	1,606	2,396	1,734	1,824	1,444	1,567		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-02	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	SCCT Frame WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	29	12	-	-	442	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	3	-	-	-	-	-	203
	Total Wind	-	-	-	70	47	29	12	-	-	442	-	200	-	-	-	3	-	-	-	-	600	803
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	7	77	-	-	-	-	3	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	4	-	-	-	3	-	-	-	-	4	-	11
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	1	-	-	4	-	31	7	81	-	-	-	-	11	1	135
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	67	61	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	504	762
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	56	126
	DSM, Class 2 Total	73	67	61	59	58	57	58	52	52	51	39	42	39	38	37	35	33	32	31	30	590	947
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	-	28
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.1	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	33	147	243	14	152	240	263	181	247	298	249	190	294	186	294	59	152
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	3	8	15	45	1	-	-	-	-	3	-	75
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	26	24	21	20	23	23	22	22	22	22	22	22	22	23	23	286	510
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	69	106
	DSM, Class 2 Total	45	49	41	41	38	34	31	28	27	30	28	27	27	28	28	26	26	26	27	27	365	635
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	103	223	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	205	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	188	161	135	116	96	96	540	91	294	790	162	163	997	256	735	256	88		
	Annual Additions, Short Term Resources	646	705	840	978	1,098	1,205	1,319	1,415	1,186	1,324	1,412	1,435	1,353	1,419	1,470	1,421	1,362	1,466	1,358	1,466		
	Total Annual Additions	791	1,482	961	1,166	1,259	1,340	1,435	1,511	1,282	1,864	1,503	1,729	2,143	1,581	1,633	2,418	1,618	2,201	1,614	1,554		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-03	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	3	-	-	-	-	-	203
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	3	-	-	-	-	600	803
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	77	-	-	-	7	4	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	-	-	0	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	10	77	-	-	-	7	26	32	-	153
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	56	54	51	49	47	45	40	42	40	30	33	30	28	27	25	23	22	21	20	487	745
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	54	49	52	51	39	42	39	38	37	35	33	32	31	30	570	926
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	44	163	263	35	175	114	141	300	300	278	105	204	300	300	300	68	151
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	6
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	22	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	26	21	-	-	-	-	24	10	-	82
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	20	20	20	20	22	22	22	19	22	22	22	22	26	279	499
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	27	26	27	25	27	27	27	24	26	26	26	26	30	357	622
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	113	233	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	183	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	213	349	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	334	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	772	121	187	160	133	112	90	95	534	262	709	119	407	258	1,164	76	743	124	210		
	Annual Additions, Short Term Resources	650	713	849	988	1,108	1,216	1,335	1,435	1,207	1,347	1,286	1,313	1,472	1,472	1,450	1,277	1,376	1,472	1,472	1,472		
	Total Annual Additions	790	1,485	970	1,175	1,268	1,349	1,447	1,525	1,302	1,881	1,548	2,022	1,591	1,879	1,708	2,441	1,452	2,215	1,596	1,682		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-1 Case C-04		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	-	661	661	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	423	423	846	411	-	411	-	-	-	-	-	-	-	1,692	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	55	51	48	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	477	735
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	68	62	58	56	57	55	53	49	50	51	39	42	38	38	37	35	33	32	31	30	560	915
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	182	68	177	-	111	176	224	-	12	34	34	119	40	40	48	98	220	105	85
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	20	19	19	19	22	19	22	22	22	23	275	482
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	66	102
	DSM, Class 2 Total	45	49	41	40	38	33	29	26	24	26	25	24	24	24	27	23	26	26	26	27	351	602
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	268	297	297	297	277	297	132	297	297	297	297	297	297	297	249	264
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	59	100	1	100	100	100	100	100	93
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(719)	(682)	8	-	-	-	-	(434)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	117	113	774	103	757	1,175	514	940	492	83	490	78	80	810	75	497	74	74		
	Annual Additions, Short Term Resources	651	714	1,222	1,354	1,240	1,349	1,143	1,283	1,348	1,396	1,152	1,184	1,041	1,165	1,291	1,113	1,212	1,220	1,270	1,392		
	Total Annual Additions	791	1,485	1,339	1,467	2,014	1,452	1,900	2,458	1,862	2,336	1,644	1,267	1,531	1,243	1,371	1,923	1,287	1,717	1,344	1,466		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-05	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	-	661	661	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	423	423	423	834	-	411	-	-	423	-	-	-	-	1,269	2,937
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	-	-	-	-	-	600	800
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	3
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	3
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	2	2	28	55
	DSM, Class 2, UT	63	55	51	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	20	20	480	738
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	55	123
	DSM, Class 2 Total	68	62	58	59	57	55	53	49	50	51	39	42	39	38	37	35	33	32	29	29	564	915
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	178	64	172	-	106	-	162	-	-	34	34	81	193	292	300	61	61	79	93
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	20	19	20	19	19	22	22	22	22	22	18	19	277	483
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	66	103
	DSM, Class 2 Total	45	49	41	40	38	33	29	26	26	26	25	24	24	27	27	26	26	26	22	22	353	603
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	263	297	68	297	267	296	119	294	297	297	297	297	-	74	226	225
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	23	100	100	100	100	51	100	100	94
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(269)	(682)	(442)	-	-	-	-	(434)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	117	187	821	133	770	1,175	516	957	915	283	490	308	80	501	76	497	804	71		
	Annual Additions, Short Term Resources	651	714	1,222	1,350	1,236	1,344	1,138	1,278	943	1,334	1,142	1,171	1,028	1,126	1,253	1,365	1,464	1,472	887	1,010		
	Total Annual Additions	791	1,485	1,339	1,537	2,057	1,477	1,908	2,453	1,459	2,291	2,057	1,454	1,518	1,434	1,333	1,866	1,540	1,969	1,691	1,081		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-06	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	411	-	-	423	846	-	-	-	-	-	1,680
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	31
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	31
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47	-	47
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	48	-	49
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	56	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	494	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	56	126
	DSM, Class 2 Total	69	63	61	59	59	57	57	52	52	51	39	42	39	38	37	35	33	32	32	31	581	938
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	42	157	254	25	169	263	-	160	282	68	121	220	256	300	298	65	131
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	-	16
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	46	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	73	-	75
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	19	19	22	22	22	22	23	26	26	285	508
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	3	4	3	3	3	71	111
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	25	25	27	28	26	26	27	30	30	365	638
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	134	251	267	297	297	297	297	297	297	297	260	297	297	297	297	297	297	297	297	257	275
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	311	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	121	118	116	106	103	95	96	95	84	495	80	82	504	924	76	812	112	198		
	Annual Additions, Short Term Resources	650	713	849	988	1,108	1,214	1,329	1,426	1,197	1,341	1,435	1,135	1,332	1,454	1,240	1,293	1,392	1,428	1,472	1,470		
	Total Annual Additions	791	1,485	970	1,106	1,224	1,320	1,432	1,521	1,293	1,436	1,519	1,630	1,412	1,536	1,744	2,217	1,468	2,240	1,584	1,668		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-07	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423	-	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	169	-	-	-	-	-	-	31	-	-	200
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	169	-	-	-	-	-	-	31	-	600	800
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	15	-	-	51
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	15	-	-	51
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	2	27	52
	DSM, Class 2, UT	63	56	54	51	50	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	492	751
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	56	125
	DSM, Class 2 Total	69	63	61	59	58	56	54	52	51	50	39	41	38	37	37	35	33	32	32	29	574	928
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	247	-	-	-	-	-	-	-	247
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	158	256	28	169	263	-	146	244	40	136	234	290	300	266	65	129
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	8
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	21
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	21	-	-	30
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	19	22	22	22	23	23	26	26	22	285	513
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	111
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	25	28	28	28	28	28	30	30	26	365	643
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	133	250	271	297	297	297	297	297	297	297	248	297	297	287	297	297	297	297	297	257	274
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	216	309	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	121	188	162	136	113	94	95	534	84	675	82	328	504	815	77	785	145	253		
	Annual Additions, Short Term Resources	650	712	848	987	1,106	1,213	1,330	1,428	1,200	1,341	1,435	1,123	1,318	1,416	1,202	1,308	1,406	1,462	1,472	1,438		
	Total Annual Additions	791	1,484	969	1,175	1,268	1,349	1,443	1,522	1,295	1,875	1,519	1,798	1,400	1,744	1,706	2,123	1,483	2,247	1,617	1,691		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-08	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	1,322	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	-	-	-	-	736	736
	CCCT J 1x1	-	-	-	-	-	-	423	846	-	-	-	-	411	-	-	423	-	423	-	-	1,269	2,526
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	27	47
	DSM, Class 2, UT	63	55	50	48	45	43	42	39	36	35	27	32	29	27	26	25	23	22	21	20	457	709
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	6	7	7	7	7	7	7	54	120
	DSM, Class 2 Total	68	62	58	56	54	52	51	48	45	45	35	40	37	36	35	33	32	30	30	29	538	876
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	184	73	176	132	263	108	-	147	183	43	169	300	40	78	91	144	270	105	126
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	35	40	33	32	29	26	22	19	17	17	17	17	17	18	18	18	18	19	19	19	271	452
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	64	99
	DSM, Class 2 Total	43	48	41	40	37	33	29	25	24	24	22	22	22	23	23	22	22	23	23	22	344	568
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	38	65	342	297	297	297	297	297	297	112	297	297	297	297	297	232	297	297	297	297	234	262
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	96	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	151	270	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	346
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(1,279)	(205)	(816)	(74)	(220)	(268)	-	-	-	-	(328)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	138	770	116	113	770	1,421	517	936	86	821	74	79	486	76	75	918	71	493	69	68		
	Annual Additions, Short Term Resources	652	716	1,224	1,356	1,245	1,348	1,304	1,435	1,280	983	1,319	1,355	1,215	1,341	1,472	1,147	1,250	1,263	1,316	1,442		
	Total Annual Additions	790	1,486	1,340	1,469	2,015	2,769	1,821	2,371	1,366	1,804	1,393	1,434	1,701	1,417	1,547	2,065	1,321	1,756	1,385	1,510		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-1 Case C-09		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	1,322	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	423	846	-	423	411	-	411	-	-	423	-	-	-	-	1,692	2,937
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	-	-	-	-	-	600	800
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	10
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	10
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	56	54	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	484	742
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	51	39	42	39	38	37	35	33	32	31	30	567	922
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	175	59	158	112	242	83	68	61	90	34	46	163	181	280	40	61	167	101	106
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	20	19	19	22	22	22	22	22	22	23	275	489
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	24	26	25	24	24	27	27	26	26	26	26	27	352	610
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	297	297	297	297	210	297	297	297	297	297	295	297	252	270
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	55	87	100	100	97
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(1,279)	(205)	(816)	(74)	(220)	(268)	-	-	-	-	(328)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	187	821	1,455	532	937	91	957	492	283	490	308	90	501	76	810	74	74		
	Annual Additions, Short Term Resources	651	714	1,219	1,347	1,231	1,330	1,284	1,414	1,255	1,240	1,233	1,262	1,119	1,218	1,335	1,353	1,452	1,167	1,218	1,339		
	Total Annual Additions	791	1,485	1,339	1,534	2,052	2,785	1,816	2,351	1,346	2,197	1,725	1,545	1,609	1,526	1,425	1,854	1,528	1,977	1,292	1,413		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-10	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	1	-	9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	81	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	4	-	15
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	2	-	12
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	2
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	100	-	11	2	11	-	130
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	56	126
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	30	581	938
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.7	0.9	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	169	263	142	107	213	293	300	51	144	192	300	65	133
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	0	-	8
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	3	-	46
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	16	45	1	-	-	-	3	-	64
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	19	22	22	22	22	22	22	23	23	284	504
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	106
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	24	27	28	28	26	26	26	27	27	361	628
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	105	99	95	96	98	84	264	743	98	134	914	499	746	77	88		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,341	1,435	1,314	1,279	1,385	1,465	1,472	1,223	1,316	1,364	1,472		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,318	1,430	1,523	1,295	1,439	1,519	1,578	2,022	1,483	1,599	2,386	1,722	2,062	1,441	1,560		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-11	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	-	-	-	-	-	600	800
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	7	74	4	4	-	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	10	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	0.1	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	1	-	-	-	0	9	0	20	95	17	4	-	-	-	1	146
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	2	2	2	30	56
	DSM, Class 2, UT	67	61	54	51	50	51	48	43	42	40	30	33	30	28	27	25	23	21	21	20	507	765
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	7	56	125
	DSM, Class 2 Total	73	67	61	59	58	61	58	52	52	51	39	42	39	38	37	35	33	30	30	29	593	946
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.7	0.9	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	30	143	238	10	147	241	253	217	251	288	221	300	61	115	241	57	138
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	11	-	45	-	1	15	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	26	24	23	20	23	23	22	22	22	22	22	22	18	18	18	289	500
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	69	106
	DSM, Class 2 Total	45	49	41	41	38	34	32	30	27	30	28	27	27	28	28	26	26	22	22	22	367	624
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	103	223	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	205	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	188	162	139	119	97	95	538	84	306	743	374	177	1,013	95	1,153	68	68		
	Annual Additions, Short Term Resources	646	705	840	978	1,098	1,202	1,315	1,410	1,182	1,319	1,413	1,425	1,389	1,423	1,460	1,393	1,472	1,233	1,287	1,413		
	Total Annual Additions	791	1,482	961	1,166	1,260	1,341	1,434	1,507	1,277	1,857	1,497	1,731	2,132	1,797	1,637	2,406	1,567	2,386	1,355	1,481		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-12	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	846	-	-	-	1,692
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	43	-	84
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	2	-	21
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	41	59	-	119
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	56	54	51	50	48	48	43	42	40	30	33	30	28	27	25	24	22	21	20	495	755
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	56	127
	DSM, Class 2 Total	69	63	61	59	59	57	57	52	52	51	39	42	39	38	37	35	34	32	32	31	581	941
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	42	157	253	25	168	263	-	40	40	172	223	300	280	286	300	65	127
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	46	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	47	-	48
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	22	22	22	23	23	26	25	26	26	285	522
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	28	28	28	29	28	30	29	30	30	365	653
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	134	251	267	297	297	297	297	297	297	297	22	177	297	297	297	297	297	297	297	257	257
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	311	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	121	118	116	106	104	95	96	95	84	748	83	83	83	927	100	924	119	183		
	Annual Additions, Short Term Resources	650	713	849	988	1,108	1,214	1,329	1,425	1,197	1,340	1,435	897	1,092	1,212	1,344	1,395	1,472	1,452	1,458	1,472		
	Total Annual Additions	791	1,485	970	1,106	1,224	1,320	1,433	1,520	1,293	1,435	1,519	1,645	1,175	1,295	1,427	2,322	1,572	2,376	1,577	1,655		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-13	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423	-	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	-	-	-	-	-	600	800
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	4	-	-	40
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	4	-	-	40
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	2	2	3	2	3	3	3	2	27	50
	DSM, Class 2, UT	63	56	54	51	50	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	492	751
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	56	125
	DSM, Class 2 Total	69	63	61	59	58	56	54	52	51	50	39	41	38	36	36	34	33	32	32	29	574	925
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	158	256	28	169	263	-	149	249	40	143	242	300	300	265	65	130
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	8
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	44
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	44	-	-	51
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	19	19	22	22	22	22	23	26	22	285	505
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	111
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	25	25	27	27	27	26	27	30	26	365	634
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	133	250	271	297	297	297	297	297	297	297	248	297	297	293	297	297	297	297	297	257	274
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	216	309	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	121	188	162	136	113	94	95	534	84	706	79	308	503	814	76	781	125	253		
	Annual Additions, Short Term Resources	650	712	848	987	1,106	1,213	1,330	1,428	1,200	1,341	1,435	1,123	1,321	1,421	1,208	1,315	1,414	1,472	1,472	1,437		
	Total Annual Additions	791	1,484	969	1,175	1,268	1,349	1,443	1,522	1,295	1,875	1,519	1,829	1,400	1,729	1,711	2,129	1,490	2,253	1,597	1,690		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-1 Case C-14		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	-	-	-	-	(416)	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	368
	CCCT GH 2x1	-	-	-	-	-	-	-	-	736	-	-	-	736	-	-	-	-	-	-	-	736	1,472
	CCCT J 1x1	-	-	-	-	-	-	423	1,269	-	-	423	411	-	-	-	846	-	-	-	-	1,692	3,372
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	3	-	-	-	-	-	203
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	3	-	-	-	-	600	803
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	6	6	6	3	3	3	3	3	1	1	1	2	1	1	1	1	1	1	46	59
	DSM, Class 2, UT	84	76	75	73	73	50	47	41	41	39	14	13	11	11	10	13	11	9	8	7	599	707
	DSM, Class 2, WY	24	24	24	24	25	3	3	3	3	2	2	2	1	2	2	2	2	1	1	1	136	153
	DSM, Class 2 Total	114	106	105	103	104	56	54	47	47	45	17	17	13	14	13	17	14	12	11	10	781	919
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.2	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	53	159	-	102	-	68	61	173	40	53	80	150	267	69	138	61	38	74
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	719	1,081
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	1	1	0	0	15	20
	DSM, Class 2, OR	37	41	34	33	31	28	24	23	21	21	21	20	21	20	20	20	21	20	20	20	293	498
	DSM, Class 2, WA	13	12	13	14	14	6	6	6	6	6	2	2	2	2	2	2	2	1	1	1	97	114
	DSM, Class 2 Total	52	55	49	49	47	35	31	30	28	28	23	22	23	23	23	23	23	22	22	22	405	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	54	23	77	297	297	292	297	220	297	297	297	6	174	297	297	297	297	297	206	185	216
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	107	75	200	236	375	375	309	375	375	375	375	375	375	375	375	375	375	375	375	375	280	328
	Existing Plant Retirements/Conversions	-	-	(164)	8	(378)	-	-	(1,258)	(779)	-	(261)	(450)	-	(459)	-	(760)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	193	822	173	240	216	137	535	1,360	827	529	480	667	789	704	53	906	54	712	50	416		
	Annual Additions, Short Term Resources	607	629	723	813	1,225	1,331	1,101	1,274	1,095	1,240	1,233	1,345	921	1,102	1,252	1,322	1,439	1,241	1,310	1,142		
	Total Annual Additions	800	1,451	896	1,053	1,441	1,468	1,636	2,634	1,922	1,769	1,713	2,012	1,710	1,806	1,305	2,228	1,493	1,953	1,360	1,558		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-15	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	-	182
	IC Aero WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	362	-	362	-	-	-	905
	SCCT Frame ID	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	-	-	-	-	181	181
	SCCT Frame WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	172	-	-	-	172	-	172	-	-	516
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	3	-	-	-	-	-	203
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	3	-	-	-	-	600	803
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	7	41	37	-	-	-	-	4	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	7	-	-	-	-	-	-	14	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	-	-	3	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.1	0.1	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	25	60	37	-	-	-	-	21	-	-	-	142
	DSM, Class 2, ID	6	6	6	6	6	2	2	1	3	3	1	1	1	1	1	1	1	1	1	1	40	52
	DSM, Class 2, UT	81	74	68	65	69	45	43	37	39	37	12	11	9	10	9	11	10	9	7	6	558	652
	DSM, Class 2, WY	23	23	23	24	24	2	2	2	2	2	2	2	1	2	1	2	2	1	1	1	129	145
	DSM, Class 2 Total	111	103	97	95	98	49	46	41	44	42	16	14	12	12	12	14	13	11	10	9	726	849
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.1	1.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	95	208	176	263	45	198	263	263	300	267	265	246	215	300	257	257	99	181
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	-	-	-	-	-	197
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	362	-	-	-	362
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	21	-	-	22	-	-	-	-	-	-	-	-	-	21	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1 Total	-	-	-	-	-	-	-	21	-	-	25	-	-	-	-	-	-	-	-	-	21	47
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	13	15
	DSM, Class 2, OR	36	41	33	32	29	26	22	19	17	17	18	17	17	17	17	17	17	17	17	17	274	443
	DSM, Class 2, WA	13	12	12	12	12	5	5	5	5	5	2	1	1	1	1	1	1	1	1	1	86	96
	DSM, Class 2 Total	51	55	47	46	43	32	28	24	23	23	20	19	19	18	18	18	18	18	18	18	373	554
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	-	297	297	297	297	297	297	297	297	297	297	297	297	297	262	229	297	178	232
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	135	160	262	400	400	400	400	400	400	400	400	400	400	387	400	397	400	400	400	400	336	367
	FOT MidColumbia Q3 - 2	375	375	375	345	375	375	375	375	375	375	375	375	375	375	368	375	375	375	375	375	372	373
	Existing Plant Retirements/Conversions	-	-	(164)	-	(387)	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	188	818	163	228	207	126	284	101	83	522	102	310	256	471	227	958	219	791	216	134		
	Annual Additions, Short Term Resources	610	635	737	845	1,267	1,380	1,348	1,435	1,217	1,370	1,435	1,435	1,472	1,426	1,430	1,415	1,387	1,437	1,361	1,429		
	Total Annual Additions	798	1,453	900	1,073	1,474	1,506	1,632	1,536	1,300	1,892	1,537	1,745	1,728	1,897	1,657	2,373	1,606	2,228	1,577	1,563		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-16	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	-	-	-	-	-	115
	Wind, GO, 29	-	-	-	-	19	9	56	50	-	466	-	-	-	-	-	-	-	-	-	-	600	600
	Total Wind	-	-	-	-	19	9	56	50	-	466	-	-	-	-	-	-	-	-	-	-	600	600
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	4	-	-	-	3	-	84
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	7	-	-	4	-	26
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	0	-	-	77	41	8	2	-	11	-	140
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	29	57
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	56	54	52	52	51	39	42	39	38	37	35	33	32	31	30	579	936
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.7	0.9	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	18	136	233	5	143	237	263	228	243	253	266	198	142	192	300	54	143
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	25	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	25	30
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	3	-	46
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	8	-	-	46	-	-	-	-	3	-	57
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	22	22	22	23	23	284	507
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	106
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	27	28	26	26	26	27	27	361	631
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	87	208	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	178	238
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	142	132	114	154	145	95	563	84	95	743	201	204	965	265	918	75	88		
	Annual Additions, Short Term Resources	650	709	845	962	1,083	1,190	1,308	1,405	1,177	1,315	1,409	1,435	1,400	1,415	1,425	1,438	1,370	1,314	1,364	1,472		
	Total Annual Additions	790	1,485	966	1,104	1,215	1,304	1,462	1,550	1,272	1,878	1,493	1,530	2,143	1,616	1,629	2,403	1,635	2,232	1,439	1,560		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-1 Case C-17	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	440	-	-	-	-	-	-	-	-	-	-	600	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	3	-	-	-	-	-	203
	Total Wind	-	-	-	70	47	30	13	-	-	440	-	200	-	-	-	3	-	-	-	-	600	803
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4	84	-	91
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	10	-	2	-	21
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	9	22	7	87	-	128
	DSM, Class 2, ID	3	3	3	4	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	61
	DSM, Class 2, UT	68	61	57	55	53	51	48	44	44	42	31	34	31	29	28	27	25	23	22	21	523	793
	DSM, Class 2, WY	4	4	5	5	6	7	7	7	7	8	7	7	7	7	8	7	7	7	8	8	60	133
	DSM, Class 2 Total	74	68	64	64	63	62	59	55	55	53	41	43	40	40	39	37	35	33	32	32	616	987
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	227	-	-	-	-	-	-	-	227
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	70	-	-	44	92	279	53	145	246	53	273	273	300	7	91
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, WV, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	42
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	42
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	44	3	-	55
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	11	21
	DSM, Class 2, OR	37	41	34	34	33	31	28	24	24	26	26	26	26	26	26	26	26	26	26	26	312	568
	DSM, Class 2, WA	8	8	8	8	8	7	7	7	7	7	5	5	5	5	5	4	4	3	3	3	74	118
	DSM, Class 2 Total	46	50	43	43	42	39	36	32	32	34	32	32	31	32	32	30	30	30	30	30	397	707
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	163	125	239	292	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	260	279
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	383	400	400	400	331	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	391	396
	FOT MidColumbia Q3 - 2	-	79	97	177	-	30	141	165	3	137	183	163	168	141	177	180	112	186	181	183	83	125
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	146	778	125	195	591	145	122	101	103	544	90	292	88	739	87	823	514	534	130	210		
	Annual Additions, Short Term Resources	646	704	836	969	728	827	938	1,032	800	934	1,024	1,052	1,244	991	1,119	1,223	962	1,256	1,251	1,280		
	Total Annual Additions	792	1,482	961	1,164	1,319	972	1,060	1,133	903	1,478	1,114	1,344	1,332	1,730	1,206	2,046	1,476	1,790	1,381	1,490		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-1 Case C-18

	Capacity (MW)																				Resource Totals 1/	
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	(416)
Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	(269)
Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	(479)
Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	(205)
Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
Expansion Resources																						
CCCT J 1x1	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	846	423	423	-	-	423	2,115
Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	2,236	-	-	-	-	-	-	-	-	2,236
Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
Wind, GO, 29	-	-	-	-	-	-	-	-	-	211	212	63	65	49	-	-	-	-	-	-	211	600
Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
Total Wind	-	-	-	-	-	-	-	-	-	211	412	63	65	49	-	-	-	-	-	-	211	800
CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2
DSM, Class 2, ID	6	6	8	8	7	3	3	3	3	3	1	1	1	2	2	2	1	1	1	1	51	65
DSM, Class 2, UT	88	81	77	81	80	51	49	43	42	40	14	13	11	12	10	14	11	10	9	8	633	744
DSM, Class 2, WY	25	25	25	26	26	3	3	3	3	3	3	2	2	2	2	2	2	2	1	1	141	159
DSM, Class 2 Total	120	112	109	115	114	58	55	48	48	46	18	17	13	15	14	17	15	13	12	10	824	967
Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	450	-	-	-	-	-	-	-	450
Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.4	13.4	13.4	131	263
Micro Solar - Water Heating	-	-	-	0.4	0.3	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
FOT Mona Q3	-	-	-	-	-	-	-	-	-	-	41	-	-	53	82	212	53	53	77	217	-	39
West																						
Existing Plant Retirements/Conversions																						
JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	(74)
Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	(74)
Coal Ret_Bridger -Gas RePower	-	-	-	-	-	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	-	362
Expansion Resources																						
Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
Wind, WV, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	300
Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	300
CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	1	0	0	1	1	1	1	1	1	0	16	22
DSM, Class 2, OR	41	44	40	38	34	31	28	25	23	23	22	21	21	21	21	21	21	21	21	21	327	536
DSM, Class 2, WA	14	14	14	14	14	7	7	6	6	6	2	2	2	3	3	3	2	2	2	2	104	126
DSM, Class 2 Total	57	60	56	55	51	38	36	33	30	30	25	24	24	24	24	24	24	23	23	23	447	684
OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Q3	99	33	-	83	113	201	297	83	-	5	297	274	-	174	297	297	226	253	297	297	91	166
FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia Q3 - 2	-	81	201	206	240	255	271	375	233	375	375	375	210	375	375	375	375	375	375	375	224	291
Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	(158)	-	-	(261)	-	(1,413)	(416)	-	(834)	-	(338)	(74)	-		
Annual Additions, Long Term Resources	203	832	183	187	183	111	106	519	95	304	471	255	2,355	555	54	1,204	478	476	52	53		
Annual Additions, Short Term Resources	599	614	701	789	853	956	1,068	958	733	880	1,213	1,149	710	1,102	1,254	1,384	1,154	1,181	1,249	1,389		
Total Annual Additions	802	1,446	884	976	1,036	1,067	1,174	1,477	828	1,184	1,684	1,404	3,065	1,657	1,308	2,588	1,632	1,657	1,301	1,442		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.8 – Energy Gateway Scenario 2 – Case C-01 to C-19

	EG-2 Case C-01	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	3.6	7.6
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	4	-	-	43	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	0	-	-	46	-	-	35	-	-	76	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	31	581	937
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	169	263	67	262	282	68	242	298	245	295	300	65	149
West	**Expansion Resources**																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	8	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	14
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	57	-	-	8	-	-	37	-	101
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	22	22	22	22	26	284	509
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	106
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	27	26	26	26	26	30	361	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	100	95	96	97	84	747	82	184	504	739	118	916	74	213		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,341	1,435	1,239	1,434	1,454	1,240	1,414	1,470	1,417	1,467	1,472		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,431	1,523	1,295	1,438	1,519	1,986	1,516	1,638	1,744	2,153	1,588	2,333	1,541	1,685		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-02	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	46	29	13	-	-	44	-	-	-	-	-	-	-	-	-	-	202	202
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	544	-	-	-	-	-	-	-	-	544
	Total Wind	-	-	-	70	46	29	13	-	-	44	-	-	544	-	-	-	-	-	-	22	202	768
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	7	-	81	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	3	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	131	-	-	7	11	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	30	581	938
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	157	254	26	169	263	67	258	300	256	299	240	266	299	242	65	157
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	203	-	181	-	-	-	-	384
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	71	-	1	-	-	7	9	-	88
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	21	23	22	22	22	22	22	22	22	26	26	281	510
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	106
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	27	28	27	27	28	28	26	26	26	30	30	359	634
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	187	159	133	113	95	96	139	84	747	626	162	284	870	256	826	91	299		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,211	1,329	1,426	1,198	1,341	1,435	1,239	1,430	1,472	1,428	1,471	1,412	1,438	1,471	1,414		
	Total Annual Additions	790	1,485	966	1,171	1,263	1,344	1,442	1,521	1,294	1,480	1,519	1,986	2,056	1,634	1,712	2,341	1,668	2,264	1,562	1,713		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case C-03		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	661	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	-	-	-	54	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	-	-	37	-	-	-	-	31	87	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	47	45	43	42	40	30	33	30	28	27	25	23	22	21	20	494	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	55	55	52	52	51	39	42	39	38	37	35	33	32	31	30	580	936
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	40	158	255	27	170	263	64	258	300	278	105	204	300	297	179	65	145
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	197
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	8	-	0	-	16
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	22	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	-	-	8	22	3	-	75
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	20	23	22	22	22	19	22	22	22	22	26	280	502
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	26	27	28	27	27	28	24	26	26	26	26	30	358	625
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	375	400	399
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	147	136	114	95	95	140	90	1,115	364	161	258	1,161	75	743	127	386		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,212	1,330	1,427	1,199	1,342	1,435	1,236	1,430	1,472	1,450	1,277	1,376	1,472	1,469	1,326		
	Total Annual Additions	790	1,485	966	1,174	1,251	1,348	1,444	1,522	1,294	1,482	1,525	2,351	1,794	1,633	1,708	2,438	1,451	2,215	1,596	1,712		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case C-04	Capacity (MW)																				Resource Totals 1/	
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	(450)
Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
Expansion Resources																						
CCCT FD 2x1	-	-	-	-	661	-	661	661	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	-	736
CCCT J 1x1	-	-	-	-	-	-	-	423	-	846	411	-	-	-	-	423	-	423	-	-	1,269	2,526
Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	27	47
DSM, Class 2, UT	63	55	50	47	45	43	41	36	36	35	27	26	29	27	26	25	23	22	21	20	452	698
DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	6	7	7	7	7	7	7	54	121
DSM, Class 2 Total	68	62	58	55	54	52	49	45	45	45	35	34	37	36	35	33	32	31	30	29	533	865
Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
FOT Mona Q3	-	-	112	187	76	189	-	131	149	203	17	63	255	38	40	40	91	104	157	282	105	107
West																						
Existing Plant Retirements/Conversions																						
JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
Expansion Resources																						
CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	-	-	423
Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
DSM, Class 2, OR	35	38	33	32	29	26	22	19	17	17	17	17	17	18	18	18	18	18	19	19	268	449
DSM, Class 2, WA	7	7	7	7	7	5	6	6	6	6	4	4	4	4	4	3	3	3	3	3	62	98
DSM, Class 2 Total	43	46	40	40	37	32	28	25	24	24	22	22	22	23	23	22	22	22	22	22	340	564
OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Q3	38	66	342	297	297	297	284	297	297	297	297	292	297	-	206	245	297	297	297	297	251	252
FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	23	100	100	100	100	100	100	96
FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia Q3 - 2	114	152	272	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	346
Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(269)	(682)	(442)	-	-	-	-	(434)	-	(338)	(74)	-		
Annual Additions, Long Term Resources	138	768	116	112	770	98	753	1,171	86	931	908	72	75	812	75	495	71	492	69	68		
Annual Additions, Short Term Resources	652	718	1,226	1,359	1,248	1,361	1,159	1,303	1,321	1,375	1,189	1,230	1,427	913	1,044	1,160	1,263	1,276	1,329	1,454		
Total Annual Additions	790	1,486	1,342	1,471	2,018	1,459	1,912	2,474	1,407	2,306	2,097	1,302	1,502	1,725	1,119	1,655	1,334	1,768	1,398	1,522		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-05	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	-	661	661	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	423	-	846	822	-	-	-	-	423	-	-	-	-	1,269	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	14	-	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	27	47
	DSM, Class 2, UT	63	55	50	47	45	43	41	36	36	35	26	26	23	27	26	25	23	22	21	20	452	691
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	6	7	7	7	7	7	7	54	121
	DSM, Class 2 Total	68	62	58	55	54	52	49	45	45	45	34	34	31	36	35	33	31	30	30	29	533	858
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	186	75	188	-	130	147	202	25	63	40	43	175	40	45	114	167	293	104	102
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	35	38	33	32	29	26	22	19	17	17	17	17	17	16	18	18	18	18	19	19	268	447
	DSM, Class 2, WA	7	7	7	7	7	5	6	6	6	6	4	4	4	4	4	3	3	3	3	3	62	98
	DSM, Class 2 Total	43	46	40	40	37	32	28	25	24	24	22	22	22	21	23	22	22	22	22	22	340	561
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	38	66	342	297	297	297	283	297	297	297	297	297	174	297	297	-	7	297	297	297	251	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	8	100	100	100	100	100	95
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	152	272	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	346
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(269)	(682)	(442)	-	-	-	-	(434)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	138	768	116	185	805	132	767	1,171	86	977	901	504	710	74	75	1,231	70	69	69	68		
	Annual Additions, Short Term Resources	652	718	1,226	1,358	1,247	1,360	1,158	1,302	1,319	1,374	1,197	1,235	1,089	1,215	1,347	823	927	1,286	1,339	1,465		
	Total Annual Additions	790	1,486	1,342	1,543	2,052	1,492	1,925	2,473	1,405	2,351	2,098	1,739	1,799	1,289	1,422	2,054	997	1,355	1,408	1,533		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-06	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	834	-	-	-	1,680
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	47	-	91
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	2	-	12
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	63	50	-	114
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	67	61	54	52	50	48	48	43	42	40	30	33	30	28	27	26	24	22	21	20	505	765
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	8	56	128
	DSM, Class 2 Total	73	67	61	60	59	57	58	53	52	51	39	43	39	38	37	36	34	32	32	31	592	953
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	33	147	243	13	154	249	-	40	40	155	204	300	292	276	299	59	122
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	46	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	3
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	47	-	49
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	23	23	23	22	23	23	23	23	26	23	26	26	291	529
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	113
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	30	30	29	28	29	29	29	28	30	27	30	30	372	660
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	243	258	297	297	297	297	297	297	297	7	160	280	297	297	297	297	297	297	254	253
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	302	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	116	107	105	96	99	98	85	748	86	84	83	929	80	910	141	174		
	Annual Additions, Short Term Resources	646	705	841	979	1,099	1,205	1,319	1,415	1,185	1,326	1,421	882	1,075	1,195	1,327	1,376	1,472	1,464	1,448	1,471		
	Total Annual Additions	791	1,482	962	1,098	1,215	1,312	1,424	1,511	1,284	1,424	1,506	1,630	1,161	1,279	1,410	2,305	1,552	2,374	1,589	1,645		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case C-07		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	14	-	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	77	-	-	-	-	-	88
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	108	-	-	-	-	-	121
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	63	61	54	52	50	48	48	43	42	40	30	33	30	28	27	25	24	22	21	20	500	759
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	7	56	126
	DSM, Class 2 Total	69	67	61	60	59	57	58	52	52	51	39	42	39	38	37	35	34	32	31	30	587	944
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	36	150	246	18	159	253	-	131	252	299	204	300	59	109	74	61	115
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	23	23	22	22	23	23	26	26	19	22	22	288	516
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	30	28	28	28	29	29	30	30	23	26	26	368	646
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	268	297	297	297	297	297	297	297	235	297	297	297	297	297	297	297	297	256	273
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	214	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	191	151	140	118	95	96	144	90	942	301	84	168	1,032	80	1,155	73	254		
	Annual Additions, Short Term Resources	650	709	845	982	1,102	1,208	1,322	1,418	1,190	1,331	1,425	1,110	1,303	1,424	1,471	1,376	1,472	1,231	1,281	1,246		
	Total Annual Additions	791	1,486	966	1,173	1,253	1,348	1,440	1,513	1,286	1,475	1,515	2,052	1,604	1,508	1,639	2,408	1,552	2,386	1,354	1,500		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	Preferred Portfolio (EG-2 Case-07a)	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	88
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	19	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	19	88	-	-	-	-	121
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	63	61	54	52	50	48	48	43	42	40	30	33	30	28	27	26	24	22	21	20	500	760
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	127
	DSM, Class 2 Total	69	67	61	60	59	57	58	52	52	51	39	42	39	38	37	36	34	32	31	30	587	946
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	37	151	248	19	161	255	-	132	253	297	292	300	59	109	74	62	119
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	23	23	22	22	23	26	26	24	19	22	22	288	517
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	30	28	28	28	29	32	30	29	23	26	26	368	647
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	262	297	297	297	297	297	297	297	237	297	297	297	297	297	297	297	297	255	273
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	119	116	106	104	95	96	98	84	942	302	84	171	944	167	1,155	73	254		
	Annual Additions, Short Term Resources	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246		
	Total Annual Additions	791	1,486	966	1,102	1,218	1,315	1,427	1,515	1,287	1,431	1,511	2,054	1,606	1,509	1,640	2,408	1,639	2,386	1,354	1,500		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-08	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	634	-	-	-	-	-	-	-	634
	CCCT FD 2x1	-	-	-	-	661	1,322	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT J 1x1	-	-	-	-	-	-	423	846	411	411	-	-	-	-	-	423	-	423	-	-	2,091	2,937
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	56	54	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	484	742
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	51	39	42	39	38	37	35	33	32	31	30	567	922
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	175	60	65	85	215	-	-	-	13	207	34	33	40	119	127	177	299	71	88
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	20	19	20	19	19	19	22	22	22	22	22	23	277	488
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	26	26	25	24	24	24	27	26	26	26	26	27	354	609
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	144	48	278	297	297	145	272	297	297	297	297	297	212	245
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	-	100	100	100	-	-	80	100	100	100	100	90	84
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(1,173)	(279)	(816)	(220)	-	(268)	-	-	-	-	(434)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	117	774	1,425	519	937	504	505	81	83	79	712	80	501	76	497	74	74		
	Annual Additions, Short Term Resources	651	714	1,219	1,347	1,232	1,237	1,257	1,387	1,019	823	1,153	1,185	1,379	954	1,080	1,192	1,291	1,299	1,349	1,471		
	Total Annual Additions	791	1,485	1,339	1,464	2,006	2,662	1,776	2,324	1,523	1,328	1,234	1,268	1,458	1,666	1,160	1,693	1,367	1,796	1,423	1,545		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-09	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_UT - Gas RePower	-	-	-	-	-	-	468	-	-	-	-	-	-	-	-	-	-	-	-	-	468	468
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	661	661	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	834	411	-	423	-	423	-	-	423	-	-	-	-	1,245	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	14	-	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	56	54	51	49	47	44	40	40	39	30	33	30	28	27	25	23	22	21	20	482	741
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	50	39	42	39	38	37	35	33	32	31	30	566	921
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	175	60	231	17	157	80	221	205	234	79	40	40	40	45	40	61	61	105	95
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	18	19	20	19	19	19	22	19	22	22	22	23	276	483
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	24	26	25	24	24	24	27	23	26	26	26	27	352	604
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	297	297	297	297	297	114	240	64	158	-	-	29	252	201
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	-	7	100	100	90
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	354	375	375	316	344
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(714)	(270)	(816)	(548)	-	(268)	-	-	-	-	(106)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	190	809	798	771	925	502	139	509	515	720	501	80	497	76	810	74	74		
	Annual Additions, Short Term Resources	651	714	1,219	1,347	1,232	1,403	1,189	1,329	1,252	1,393	1,377	1,406	1,251	1,029	1,155	979	1,078	794	843	965		
	Total Annual Additions	791	1,485	1,339	1,537	2,041	2,201	1,960	2,254	1,754	1,532	1,886	1,921	1,971	1,530	1,235	1,476	1,154	1,604	917	1,039		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case C-10		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	368
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	ICE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	103	-	-	-	-	103
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	-	-	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	-	-	-	-	-	172
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.7	0.4	0.4	0.7	2.6	0.7	0.4	3.6	10.3
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	4	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	3	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	13	10	-	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	102	32	-	-	-	7	-	10	-	152
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	3	3	3	3	3	3	3	2	31	58
	DSM, Class 2, UT	67	61	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	504	763
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	7	7	8	7	7	7	7	8	56	128
	DSM, Class 2 Total	73	67	61	59	58	57	58	52	52	51	40	43	39	38	37	35	33	32	31	30	591	950
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	34	148	244	14	155	249	263	296	298	273	298	298	232	279	300	60	169
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	-	-	0.3
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	8	8	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	6	-	-	-	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	19	53	7	-	-	6	-	-	3	-	87
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	26	24	22	23	23	23	22	24	26	22	22	26	26	26	26	290	532
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	5	5	4	3	4	3	3	3	69	109
	DSM, Class 2 Total	45	49	41	41	38	34	31	29	30	30	28	27	30	32	28	26	30	30	30	30	368	659
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	104	224	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	205	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	118	115	105	105	96	99	98	85	107	664	217	263	911	189	930	78	457		
	Annual Additions, Short Term Resources	646	705	840	979	1,099	1,206	1,320	1,416	1,186	1,327	1,421	1,435	1,468	1,470	1,445	1,470	1,470	1,404	1,451	1,472		
	Total Annual Additions	791	1,482	961	1,097	1,214	1,311	1,425	1,512	1,285	1,425	1,506	1,542	2,132	1,687	1,708	2,381	1,659	2,334	1,529	1,929		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-11	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	661	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	14	-	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	4	74	-	-	-	-	-	-	-	77
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	10
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	20	4	74	-	-	-	-	-	-	-	97
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	2	2	2	3	2	2	30	54
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	26	25	23	22	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	55	123
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	35	34	32	32	30	29	581	930
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	157	254	26	168	261	263	296	300	40	42	144	251	147	273	64	133
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	10	-	44	-	-	-	-	-	-	-	55
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	21	23	22	22	22	18	18	19	19	18	18	282	483
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	104
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	28	28	27	27	28	23	22	23	23	22	22	359	604
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	122	297	297	297	297	297	182	231
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	148	138	114	95	96	142	91	548	485	199	736	733	71	732	249	68		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,211	1,329	1,426	1,198	1,340	1,433	1,435	1,468	1,472	1,037	1,214	1,316	1,423	1,319	1,445		
	Total Annual Additions	790	1,485	966	1,174	1,252	1,349	1,443	1,521	1,294	1,482	1,524	1,983	1,953	1,671	1,773	1,947	1,387	2,155	1,568	1,513		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-12	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	834	-	-	-	1,680
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	47	-	84
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	2	-	21
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	65	50	-	116
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	67	61	54	52	50	48	48	43	42	40	30	33	30	28	27	26	24	22	21	20	505	765
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	8	56	128
	DSM, Class 2 Total	73	67	61	60	59	57	58	53	52	51	39	43	39	38	37	36	34	32	32	31	592	953
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	33	147	243	13	154	249	-	40	40	155	204	300	292	274	297	59	122
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	46	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	3
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	47	-	49
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	23	23	23	22	23	23	23	23	26	23	26	26	291	529
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	113
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	30	30	29	28	29	29	29	28	30	27	30	30	372	660
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	243	258	297	297	297	297	297	297	297	6	160	280	297	297	297	297	297	297	254	253
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	302	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	116	107	105	96	99	98	85	749	85	84	83	929	80	910	143	174		
	Annual Additions, Short Term Resources	646	705	841	979	1,099	1,205	1,319	1,415	1,185	1,326	1,421	881	1,075	1,195	1,327	1,376	1,472	1,464	1,446	1,469		
	Total Annual Additions	791	1,482	962	1,098	1,215	1,312	1,424	1,511	1,284	1,424	1,506	1,630	1,160	1,279	1,410	2,305	1,552	2,374	1,589	1,643		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-13	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	**10-year**	**20-year**
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	14	-	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	4	-	-	15
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	42	25	-	-	69
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	32	60
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	28	27	25	23	22	22	20	508	768
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	6	7	8	7	7	7	8	7	56	127
	DSM, Class 2 Total	73	67	61	60	59	61	58	53	52	51	40	43	39	38	37	35	33	32	32	30	597	956
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	25	139	234	4	145	238	263	40	40	137	190	288	300	300	265	55	130
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	2	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	21	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	46	21	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	22	22	22	22	23	24	26	26	22	295	526
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	4	4	3	3	3	71	113
	DSM, Class 2 Total	45	49	42	41	40	35	32	31	30	30	29	28	28	28	28	28	28	30	30	26	376	659
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	242	263	297	297	297	297	297	297	297	297	141	263	297	297	297	297	297	297	254	266
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	97	214	298	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	258	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	192	153	145	119	98	99	144	91	526	962	82	82	925	78	828	125	254		
	Annual Additions, Short Term Resources	646	705	839	977	1,095	1,197	1,311	1,406	1,176	1,317	1,410	1,435	1,056	1,178	1,309	1,362	1,460	1,472	1,472	1,437		
	Total Annual Additions	791	1,482	960	1,169	1,248	1,342	1,430	1,504	1,275	1,461	1,501	1,961	2,018	1,260	1,391	2,287	1,538	2,300	1,597	1,691		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-14	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	-	-	-	-	(416)	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	661	-	-	-	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	423	1,257	423	423	411	-	-	-	423	-	-	-	-	-	2,526	3,360
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	6	6	7	3	3	3	3	3	1	1	1	2	1	1	1	1	1	1	47	60
	DSM, Class 2, UT	84	76	75	73	79	50	47	41	41	39	14	13	11	11	10	13	11	9	8	7	605	713
	DSM, Class 2, WY	24	24	24	25	25	3	3	3	3	2	2	2	1	2	2	2	2	1	1	1	137	154
	DSM, Class 2 Total	114	106	105	104	111	57	54	47	47	45	17	17	13	14	13	16	14	12	11	10	789	928
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.2	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	47	152	-	104	219	20	23	-	47	40	40	40	136	40	40	149	54	55
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	719	1,081
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	1	1	0	0	15	20
	DSM, Class 2, OR	37	41	34	33	31	28	24	23	21	21	21	20	20	20	20	20	20	20	20	21	293	497
	DSM, Class 2, WA	13	13	13	14	14	6	6	6	6	6	2	2	2	2	2	2	2	2	2	2	97	115
	DSM, Class 2 Total	52	55	49	49	47	35	31	30	28	28	23	22	22	23	23	23	23	23	23	23	405	633
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	54	23	77	297	297	285	297	297	297	297	130	297	282	85	277	297	195	264	297	192	217
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	107	75	200	236	375	375	309	375	375	375	375	375	375	375	375	375	375	375	375	375	280	328
	Existing Plant Retirements/Conversions	-	-	(164)	8	(378)	-	-	(1,258)	(779)	-	(261)	(450)	-	(459)	-	(760)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	193	822	173	243	211	140	537	1,348	514	557	473	1,160	334	715	475	717	54	713	50	71		
	Annual Additions, Short Term Resources	607	629	723	813	1,219	1,324	1,094	1,276	1,391	1,192	1,195	1,005	1,219	1,197	1,000	1,192	1,308	1,110	1,179	1,321		
	Total Annual Additions	800	1,451	896	1,056	1,430	1,464	1,631	2,624	1,905	1,749	1,668	2,165	1,553	1,912	1,475	1,909	1,362	1,823	1,229	1,392		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Region	EG-2 Case C-15	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	362	-	362	-	-	-	905
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	181	-	-	362
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	343	172	-	-	-	-	515
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	2.7	2.7	2.7	0.4	0.4	3.6	14.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	4	-	-	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	19	3	-	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	3	19	-	-	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	-	92	37	3	4	-	4	-	-	-	142
	DSM, Class 2, ID	6	6	6	6	6	2	2	2	2	3	1	1	1	2	1	1	1	1	1	1	39	52
	DSM, Class 2, UT	81	74	68	65	63	39	37	37	37	37	12	11	9	10	9	12	11	9	7	6	537	634
	DSM, Class 2, WY	23	23	23	23	24	2	2	2	2	2	2	2	1	2	2	2	2	1	1	1	128	144
	DSM, Class 2 Total	111	103	97	94	92	43	41	41	41	42	16	14	11	13	12	15	14	12	10	9	704	830
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	6	115	-	56	170	230	184	294	292	269	237	300	215	283	18	133
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	-	-	-	197
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	15
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-	-	-	16
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	0	0	0	0	12	16
	DSM, Class 2, OR	36	41	33	32	29	26	22	19	17	17	18	17	18	17	17	19	19	19	17	17	274	451
	DSM, Class 2, WA	12	12	12	12	12	5	5	5	5	5	2	1	1	1	1	2	1	1	1	1	86	98
	DSM, Class 2 Total	51	55	47	46	43	32	28	24	23	23	20	19	19	19	19	21	21	20	18	18	372	566
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	-	56	175	297	297	197	297	297	297	297	297	297	297	297	297	297	297	132	214
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	135	160	262	371	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	333	366
	FOT MidColumbia Q3 - 2	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	188	818	163	231	188	122	98	80	80	126	58	418	619	86	233	961	225	779	225	156		
	Annual Additions, Short Term Resources	610	635	737	846	931	1,050	1,178	1,287	1,072	1,228	1,342	1,402	1,356	1,466	1,464	1,441	1,409	1,472	1,387	1,455		
	Total Annual Additions	798	1,453	900	1,077	1,119	1,172	1,276	1,367	1,152	1,354	1,400	1,820	1,975	1,552	1,697	2,402	1,634	2,251	1,612	1,611		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case C-16		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	-	-	-	-	-	115
	Wind, GO, 29	-	-	-	-	63	-	-	-	-	63	-	-	-	-	-	-	-	-	-	-	126	126
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	446	-	-	-	-	-	-	-	-	446
	Total Wind	-	-	-	-	63	-	-	-	-	63	-	-	446	-	-	-	-	-	-	-	126	572
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	-	-	81	-	-	-	-	-	-	85
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	4	0	-	89	-	-	-	-	-	-	93
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	3	3	3	2	2	2	2	2	31	55
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	56	124
	DSM, Class 2 Total	69	67	61	59	57	57	55	52	52	51	39	42	39	38	37	33	31	30	30	29	582	932
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	16	135	232	3	144	236	263	293	300	300	40	40	116	170	296	53	129
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	25	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	25	30
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	3	4	4	8	44	-	-	-	-	-	-	63
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	18	18	18	18	18	283	487
	DSM, Class 2, WA	8	7	7	7	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	22	22	22	22	22	361	610
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	87	207	297	297	297	297	297	297	297	297	297	297	163	266	297	297	297	178	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	142	177	105	100	95	96	161	87	94	714	210	214	1,394	70	730	68	68		
	Annual Additions, Short Term Resources	650	709	845	962	1,082	1,188	1,307	1,404	1,175	1,316	1,408	1,435	1,465	1,472	1,472	1,078	1,181	1,288	1,342	1,468		
	Total Annual Additions	790	1,485	966	1,104	1,259	1,293	1,407	1,499	1,271	1,477	1,495	1,529	2,179	1,682	1,686	2,472	1,251	2,018	1,410	1,536		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-17	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	846	-	-	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	4	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	62
	DSM, Class 2, UT	68	61	57	55	53	51	48	44	44	42	31	34	30	29	27	26	24	22	21	20	523	788
	DSM, Class 2, WY	4	4	5	5	6	6	7	7	7	8	7	7	7	7	8	7	7	7	7	8	59	132
	DSM, Class 2 Total	74	68	64	64	63	61	59	55	55	53	41	43	40	39	38	36	34	32	32	31	615	981
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	70	-	-	53	103	288	54	180	228	300	53	53	53	7	72
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	11	20
	DSM, Class 2, OR	37	41	34	34	33	31	27	24	24	24	24	23	25	26	26	26	26	23	26	26	308	558
	DSM, Class 2, WA	8	8	8	8	8	7	7	7	7	7	5	5	5	5	5	4	4	3	3	3	74	118
	DSM, Class 2 Total	46	50	43	43	42	39	35	32	32	32	30	29	31	32	32	30	30	28	30	30	393	695
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	163	125	239	291	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	260	279
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	383	400	400	400	331	400	400	400	400	400	400	400	400	400	400	400	400	379	400	400	391	395
	FOT MidColumbia Q3 - 2	-	79	97	178	-	31	143	166	4	143	183	163	168	174	177	180	202	-	26	145	84	113
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	146	778	125	198	578	147	122	101	103	147	92	457	369	510	86	929	81	1,399	78	99		
	Annual Additions, Short Term Resources	646	704	836	969	728	828	940	1,033	801	940	1,033	1,063	1,253	1,025	1,154	1,205	1,299	829	876	995		
	Total Annual Additions	792	1,482	961	1,167	1,306	975	1,062	1,134	904	1,087	1,125	1,520	1,622	1,535	1,240	2,134	1,380	2,228	954	1,094		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-18	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	(479)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	WY IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	456	-	456
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	846	411	-	-	2,103
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	2,236	-	-	-	-	-	-	-	-	2,236
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	Wind, GO, 29	-	-	-	-	-	-	-	-	-	-	393	63	84	59	-	-	-	-	-	-	-	599
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
	Wind, Wyoming, 40	-	-	-	-	-	-	-	650	-	-	-	-	-	-	-	-	-	-	-	-	650	650
	Total Wind	-	-	-	-	-	-	-	650	-	-	593	63	84	59	-	-	-	-	-	-	650	1,449
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	8	8	7	3	3	3	3	3	1	1	1	2	2	2	1	1	1	1	51	65
	DSM, Class 2, UT	88	81	77	81	80	51	49	43	42	40	14	13	11	12	10	14	11	10	9	8	633	743
	DSM, Class 2, WY	25	25	25	26	26	3	3	3	3	3	3	2	2	2	2	2	2	2	1	1	141	159
	DSM, Class 2 Total	120	112	109	115	114	58	55	48	48	46	18	17	13	15	14	17	15	13	12	10	824	967
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	450	-	-	-	-	-	-	-	450
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.4	13.4	13.4	131	263
	Micro Solar - Water Heating	-	-	-	0.4	0.3	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	-	-	-	6	180	-	53	103	168	284	285	82	53	-	61
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	-	-	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	-	362
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	Wind, WV, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	300
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	300
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	1	0	0	1	1	1	1	1	1	0	16	22
	DSM, Class 2, OR	41	44	40	38	34	31	28	25	23	23	22	21	21	21	21	21	21	21	21	21	327	535
	DSM, Class 2, WA	14	14	14	14	14	7	7	6	6	6	2	2	2	3	3	3	2	2	2	2	104	127
	DSM, Class 2 Total	57	60	56	55	51	38	36	33	30	30	25	24	24	24	24	24	24	23	23	23	447	684
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	99	33	-	83	113	201	297	286	60	210	297	297	-	195	297	297	297	297	297	65	138	186
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	-	81	201	206	240	255	271	375	375	375	375	375	210	375	375	375	375	375	375	375	238	298
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	8	(269)	(1,208)	(416)	-	(760)	-	(701)	(148)	-		
	Annual Additions, Long Term Resources	203	832	183	187	183	111	106	746	95	93	652	255	2,374	565	54	1,204	55	899	462	506		
	Annual Additions, Short Term Resources	599	614	701	789	853	956	1,068	1,161	935	1,085	1,178	1,352	710	1,123	1,275	1,340	1,456	1,457	1,254	993		
	Total Annual Additions	802	1,446	884	976	1,036	1,067	1,174	1,907	1,030	1,178	1,830	1,607	3,084	1,688	1,329	2,544	1,511	2,356	1,716	1,499		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case C-19	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	736
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	181	-	-	-	362
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	22	-	38
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	16	-	-	-	-	22	199	892
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	7	77	-	-	-	-	3	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	4	-	8
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	10	-	3	9	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	1	-	-	0	10	-	11	99	-	-	-	-	11	1	131
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	32	60
	DSM, Class 2, UT	67	61	54	51	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	507	766
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	56	126
	DSM, Class 2 Total	73	67	61	59	59	61	58	52	52	51	39	42	39	38	37	35	33	32	31	30	595	952
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.1	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	29	143	237	8	149	241	255	217	268	300	253	196	142	192	300	57	147
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	3	8	-	60	1	-	-	-	-	3	-	75
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	26	24	23	20	23	23	22	22	22	22	19	20	22	22	23	289	506
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	69	106
	DSM, Class 2 Total	45	49	41	41	38	34	32	30	27	30	28	27	27	28	28	23	24	26	26	27	367	630
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	103	223	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	205	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	191	149	143	118	99	96	143	92	472	1,025	153	197	991	254	916	74	110		
	Annual Additions, Short Term Resources	646	705	840	978	1,098	1,201	1,315	1,409	1,180	1,321	1,413	1,427	1,389	1,440	1,472	1,425	1,368	1,314	1,364	1,472		
	Total Annual Additions	791	1,482	961	1,169	1,247	1,344	1,433	1,508	1,276	1,464	1,505	1,899	2,414	1,593	1,669	2,416	1,622	2,230	1,438	1,582		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.9 – Energy Gateway Scenario 3 – Case C-01 to C-19

	EG-3 Case C-01	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	-	-	-	91
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	-	-	-	-	-	172
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	7.9	7.9	7.9	7.9	-	39.5
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.8	2.7	2.7	2.7	2.7	2.7	2.7	3.7	3.7	3.6	28.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	4	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	15	3	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	13	10	-	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	106	13	-	-	23	3	1	11	-	158
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	61
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	29	28	27	25	23	23	21	508	777
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	8	7	7	7	7	8	7	7	8	8	8	57	131
	DSM, Class 2 Total	73	67	61	61	59	61	58	53	52	52	40	43	40	39	38	37	35	34	33	32	597	969
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	27	140	235	4	145	239	263	298	300	269	279	300	300	300	300	55	170
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	IC Aero WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	99	-	198
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	5	-	40
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	2.3	2.3	2.3	2.3	-	11.6
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	-	2.7
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	21	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	2	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	1	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	6	44	22	-	-	39	-	1	5	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 2, OR	37	41	33	32	29	28	27	23	23	23	23	26	26	26	26	26	26	26	26	26	296	549
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	5	5	5	5	4	4	4	4	3	69	112
	DSM, Class 2 Total	46	49	41	41	38	35	34	30	30	30	28	32	31	32	32	31	30	30	31	30	375	682
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	102	222	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	204	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	115	111	108	98	99	98	85	98	664	217	270	930	156	857	132	290		
	Annual Additions, Short Term Resources	646	704	840	977	1,097	1,199	1,312	1,407	1,176	1,317	1,411	1,435	1,470	1,472	1,441	1,451	1,472	1,472	1,472	1,472		
	Total Annual Additions	791	1,481	961	1,096	1,212	1,310	1,420	1,505	1,275	1,415	1,496	1,533	2,134	1,689	1,711	2,381	1,628	2,329	1,604	1,762		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-02	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	661	-	-	-	1,983
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	-	-	-	-	368
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	22	15	-	-	48	-	-	-	-	-	-	-	-	-	-	202	202
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	540	-	-	-	-	-	-	-	-	540
	Total Wind	-	-	-	70	47	22	15	-	-	48	-	-	540	-	-	-	-	-	-	-	202	742
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	4	-	-	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	85
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	6	111	-	24	-	-	-	-	-	-	141
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	2	2	2	2	2	30	53
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	21	21	20	495	752
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	55	123
	DSM, Class 2 Total	69	67	61	59	57	56	54	52	52	51	39	42	39	38	37	33	31	30	30	29	580	928
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	158	255	27	168	262	263	300	191	300	172	273	40	61	167	65	134
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	5	-	40
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	28	44	-	-	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	22	22	22	18	18	18	18	18	283	486
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	104
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	29	28	27	26	27	27	22	22	22	22	22	361	608
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	297	297	290	297	297	182	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	(387)	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	187	160	126	114	95	96	145	84	120	777	742	104	1,101	70	1,153	103	151		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,211	1,330	1,427	1,199	1,340	1,434	1,435	1,472	1,363	1,472	1,344	1,445	1,205	1,233	1,339		
	Total Annual Additions	790	1,485	966	1,171	1,264	1,337	1,444	1,522	1,295	1,485	1,518	1,555	2,249	2,105	1,576	2,445	1,515	2,358	1,336	1,490		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-03	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	1,322	-	-	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	74	35	33	12	-	-	44	4	-	-	-	-	-	-	-	-	-	198	202
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	398	236	-	-	-	-	-	-	-	-	634
	Total Wind	-	-	-	74	35	33	12	-	-	44	4	398	236	-	-	-	-	-	-	-	198	836
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	77	-	-	-	-	7	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	10	-	-	13	-	-	-	-	2	-	25
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	11	-	16	111	-	-	-	-	14	-	153
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	2	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	34	33	32	31	30	581	935
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	157	254	26	168	262	263	226	300	300	40	40	181	200	300	64	138
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	78	-	92
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	78	-	92
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	5	-	40
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	8	-	8	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	22	21	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	20	-	31	21	-	-	-	-	3	-	75
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	22	22	22	18	19	19	22	22	283	494
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	29	28	27	27	28	28	22	22	23	26	26	361	617
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	162	264	297	297	297	182	231
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	191	148	137	112	95	96	141	88	515	979	143	214	1,395	72	675	108	173		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,211	1,329	1,426	1,198	1,340	1,434	1,435	1,398	1,472	1,472	1,077	1,179	1,353	1,372	1,472		
	Total Annual Additions	790	1,485	966	1,175	1,252	1,348	1,441	1,521	1,294	1,481	1,522	1,950	2,377	1,615	1,686	2,472	1,251	2,028	1,480	1,645		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-04		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	-	-	1,322	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	736	-	-	-	-	-	-	-	-	-	-	736	-	-	736	1,472
	CCCT J 1x1	-	-	-	-	-	-	-	-	846	834	-	-	-	423	-	-	-	-	-	-	1,680	2,103
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	4	-	-	-	-	-	41
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	8	-	40	4	-	-	-	-	-	52
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	2	2	2	29	54
	DSM, Class 2, UT	63	55	51	48	49	47	44	40	41	40	30	33	30	28	27	26	25	22	21	20	477	739
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	55	123
	DSM, Class 2 Total	68	62	58	56	57	55	53	49	51	51	39	42	39	38	37	36	34	31	30	29	561	916
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	182	68	177	-	-	-	-	67	97	281	54	137	205	300	40	73	199	54	100
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	2
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	20	20	23	22	22	22	26	26	26	18	19	19	277	500
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	66	103
	DSM, Class 2 Total	45	48	41	40	38	33	29	26	26	27	28	27	27	27	31	30	30	22	23	22	353	620
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	202	116	122	273	297	297	297	297	297	297	297	277	297	297	205	250
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(1,047)	(788)	8	-	-	-	-	-	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	117	113	774	103	832	1,413	940	928	84	86	90	507	124	86	81	805	69	68		
	Annual Additions, Short Term Resources	651	714	1,222	1,354	1,240	1,349	1,077	991	997	1,148	1,239	1,269	1,453	1,226	1,309	1,377	1,472	1,192	1,245	1,371		
	Total Annual Additions	791	1,485	1,339	1,467	2,014	1,452	1,909	2,404	1,937	2,076	1,323	1,355	1,543	1,733	1,433	1,463	1,553	1,997	1,314	1,439		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-05	Capacity (MW)																				Resource Totals 1/	
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	(450)
Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
Expansion Resources																						
CCCT FD 2x1	-	-	-	-	-	-	661	1,322	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
CCCT GH 2x1	-	-	-	-	736	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	736	1,472
CCCT J 1x1	-	-	-	-	-	-	-	-	-	846	822	-	423	-	-	-	-	-	-	-	846	2,091
Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4	-	-	-	-	-	7
DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	4	-	-	-	3	-	-	-	-	-	-	7
DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	4	8	3	-	3	4	-	-	-	-	-	22
DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
DSM, Class 2, UT	63	55	54	51	49	47	45	43	42	40	30	33	30	28	28	28	25	22	21	20	489	753
DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	124
DSM, Class 2 Total	69	62	61	59	57	55	54	52	52	51	39	42	39	38	38	37	35	32	31	30	574	935
Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
FOT Mona Q3	-	-	109	175	-	102	-	-	199	244	55	74	40	40	141	206	300	61	71	196	83	101
West																						
Existing Plant Retirements/Conversions																						
JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
Expansion Resources																						
Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	4
DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	8	2	2	-	-	-	-	-	12
DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	19
DSM, Class 2, OR	36	40	33	32	29	26	22	21	20	23	23	22	23	26	26	26	26	18	19	19	283	510
DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	5	5	4	4	3	3	3	67	107
DSM, Class 2 Total	45	49	41	41	38	33	29	28	27	30	28	27	28	32	32	31	30	22	23	22	359	635
OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Q3	37	64	342	297	291	297	192	102	297	297	297	297	170	281	297	297	297	255	297	297	222	250
FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(703)	(682)	(442)	-	-	-	-	-	-	(338)	(74)	-		
Annual Additions, Long Term Resources	140	771	120	190	884	137	772	1,419	96	989	916	526	727	94	92	90	82	806	70	70		
Annual Additions, Short Term Resources	651	714	1,219	1,347	1,166	1,274	1,067	977	1,371	1,416	1,227	1,246	1,085	1,196	1,313	1,378	1,472	1,191	1,243	1,368		
Total Annual Additions	791	1,485	1,339	1,537	2,050	1,411	1,839	2,396	1,467	2,405	2,143	1,772	1,812	1,290	1,405	1,468	1,554	1,997	1,313	1,438		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-06	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	2	3	3	3	3	3	3	3	32	59
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	508	767
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	6	7	7	7	7	7	7	7	56	126
	DSM, Class 2 Total	73	67	61	60	59	61	58	53	52	51	40	43	38	38	37	35	33	32	31	30	596	952
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	28	142	237	6	148	241	263	40	40	147	201	300	59	109	232	56	110
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	11
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	22	19	19	19	22	22	19	22	22	295	504
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	3	3	3	3	3	71	110
	DSM, Class 2 Total	45	49	42	41	40	35	32	31	30	30	29	28	25	24	24	26	26	23	26	26	376	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	243	258	297	297	297	297	297	297	297	297	145	269	297	297	297	297	297	297	254	266
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	220	300	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	117	111	105	98	99	98	85	100	740	79	78	923	76	1,155	73	73		
	Annual Additions, Short Term Resources	646	705	841	978	1,097	1,200	1,314	1,409	1,178	1,320	1,413	1,435	1,060	1,184	1,319	1,373	1,472	1,231	1,281	1,404		
	Total Annual Additions	791	1,482	962	1,097	1,214	1,311	1,419	1,507	1,277	1,418	1,498	1,535	1,800	1,263	1,397	2,296	1,548	2,386	1,354	1,477		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-07	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	-	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	14	-	-	664
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	14	-	202	872
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	4	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	40	-	-	51
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	3
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	27	44	-	-	87
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	61	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	499	759
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	127
	DSM, Class 2 Total	69	67	61	59	59	57	57	52	52	51	39	42	39	38	37	35	33	32	32	30	586	945
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	36	151	248	19	162	257	-	134	255	298	40	40	297	300	277	62	126
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	22	22	22	23	22	23	26	26	22	285	516
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	28	28	28	29	27	28	30	30	26	365	646
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	268	297	297	297	297	297	297	297	238	297	297	297	156	254	297	297	297	256	264
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	215	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	166	259	307
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	191	151	140	117	96	96	141	90	942	302	83	172	1,400	77	528	136	493		
	Annual Additions, Short Term Resources	650	709	845	983	1,102	1,208	1,323	1,420	1,191	1,334	1,429	1,113	1,306	1,427	1,470	1,071	1,169	1,469	1,472	1,240		
	Total Annual Additions	791	1,486	966	1,174	1,253	1,348	1,440	1,516	1,287	1,475	1,519	2,055	1,608	1,510	1,642	2,471	1,246	1,997	1,608	1,733		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-08	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	1,322	661	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	736	-	-	-	1,472
	CCCT J 1x1	-	-	-	-	-	-	423	846	411	-	-	-	-	-	411	-	-	-	-	-	1,680	2,091
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	3	3	3	3	3	3	3	3	27	54
	DSM, Class 2, UT	63	55	50	48	45	43	41	38	39	39	30	32	30	28	27	25	23	22	21	20	462	719
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	123
	DSM, Class 2 Total	68	62	58	56	54	52	49	47	49	49	38	41	38	38	37	35	33	32	31	30	543	896
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	185	-	176	18	150	75	219	-	-	142	265	57	132	231	129	178	300	94	118
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	35	40	33	32	29	26	22	19	17	17	17	19	19	19	19	22	22	22	22	23	271	475
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	63	100
	DSM, Class 2 Total	43	48	40	40	37	33	29	25	24	24	22	24	24	24	24	26	26	26	26	27	343	592
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	38	65	342	297	196	297	297	297	297	297	211	245	297	297	297	297	297	297	297	297	242	263
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	151	270	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	346
	Existing Plant Retirements/Conversions	-	-	(582)	8	(828)	(829)	(74)	(816)	(548)	-	(268)	-	-	-	-	-	-	(543)	(74)	-		
	Annual Additions, Long Term Resources	138	770	116	113	1,431	760	516	934	500	90	813	81	79	78	488	78	76	810	74	74		
	Annual Additions, Short Term Resources	652	716	1,224	1,357	1,071	1,348	1,190	1,322	1,247	1,391	1,086	1,120	1,314	1,437	1,229	1,304	1,403	1,301	1,350	1,472		
	Total Annual Additions	790	1,486	1,340	1,470	2,502	2,108	1,706	2,256	1,747	1,481	1,899	1,201	1,393	1,515	1,717	1,382	1,479	2,111	1,424	1,546		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-09	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_UT - Gas RePower	-	-	-	-	-	-	468	-	-	-	-	-	-	-	-	-	-	-	-	-	468	468
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT F 2x1	-	-	-	-	-	-	634	-	-	-	-	-	-	-	-	-	-	-	-	-	634	634
	CCCT FD 2x1	-	-	-	-	661	661	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	846	423	411	411	-	423	-	-	-	-	-	-	-	1,680	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	56	54	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	484	742
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	51	39	42	39	38	37	35	33	32	31	30	567	922
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	175	60	231	41	171	85	-	-	4	40	40	102	177	40	40	61	164	87	77
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	19	19	19	19	19	22	22	22	22	22	275	481
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	66	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	25	24	26	25	24	24	24	24	26	26	26	26	26	351	602
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	297	279	273	297	107	231	297	297	-	249	278	297	250	242
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	-	100	100	100	100	95
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	369	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(714)	(270)	(816)	(548)	(106)	(268)	-	-	-	-	-	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	190	809	798	743	938	514	551	497	515	720	78	77	78	812	74	74	73		
	Annual Additions, Short Term Resources	651	714	1,219	1,347	1,232	1,403	1,213	1,343	1,257	1,154	1,148	1,176	1,022	1,146	1,274	1,349	809	1,164	1,214	1,336		
	Total Annual Additions	791	1,485	1,339	1,537	2,041	2,201	1,956	2,281	1,771	1,705	1,645	1,691	1,742	1,224	1,351	1,427	1,621	1,238	1,288	1,409		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-10		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	-	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	-	-	-	-	-	172
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	77	-	-	-	-	81
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	-	-	13	-	-	99	-	-	-	-	113
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	2	2	2	30	56
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	21	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	55	124
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	30	30	29	581	933
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	170	263	67	262	300	276	300	299	40	47	174	65	134
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	71	-	1	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	21	23	22	22	22	22	22	22	18	18	18	282	493
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	28	28	27	27	28	27	26	26	22	22	22	359	615
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	251	297	297	182	237
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	100	95	96	96	85	747	82	174	262	912	175	1,228	68	68		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,342	1,435	1,239	1,434	1,472	1,448	1,472	1,471	1,166	1,219	1,346		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,431	1,523	1,295	1,438	1,520	1,986	1,516	1,646	1,710	2,384	1,646	2,394	1,287	1,414		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-11		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	661	-	-	-	1,983
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	368
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	33	13	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	684	-	-	-	-	-	-	-	-	684
	Total Wind	-	-	-	73	35	33	13	-	-	45	5	-	684	-	-	-	-	-	-	-	199	888
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	4	-	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	81	-	-	4	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	7	11	-	-	3	-	-	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	16	120	-	-	11	-	-	-	10	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	8	55	126
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	30	581	938
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	157	254	26	167	261	258	300	190	294	300	241	203	258	208	64	158
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	-	-	197
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	6
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	21	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	22	28	-	28	-	-	-	-	3	-	82
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	22	19	22	22	23	284	503
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	106
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	26	23	26	26	27	361	627
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	369	400	398
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	364	348	343	375	333	350
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	(387)	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	148	137	113	95	96	142	89	124	915	751	110	931	269	916	73	455		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,211	1,329	1,426	1,198	1,339	1,433	1,430	1,472	1,362	1,466	1,472	1,402	1,348	1,398	1,349		
	Total Annual Additions	790	1,485	966	1,174	1,252	1,348	1,442	1,521	1,294	1,481	1,522	1,554	2,387	2,113	1,576	2,403	1,671	2,264	1,471	1,804		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-12	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	2	3	3	3	3	3	3	3	32	59
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	508	767
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	6	7	7	7	7	7	7	7	56	126
	DSM, Class 2 Total	73	67	61	60	59	61	58	53	52	51	40	43	38	38	37	35	33	32	31	30	596	952
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	28	142	237	6	148	241	263	40	40	147	201	300	59	109	232	56	110
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	11
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	22	19	19	19	22	22	19	22	22	295	504
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	3	3	3	3	3	71	110
	DSM, Class 2 Total	45	49	42	41	40	35	32	31	30	30	29	28	25	24	24	26	26	23	26	26	376	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	243	258	297	297	297	297	297	297	297	297	145	269	297	297	297	297	297	297	254	266
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	220	300	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	117	111	105	98	99	98	85	100	740	79	78	923	76	1,155	73	73		
	Annual Additions, Short Term Resources	646	705	841	978	1,097	1,200	1,314	1,409	1,178	1,320	1,413	1,435	1,060	1,184	1,319	1,373	1,472	1,231	1,281	1,404		
	Total Annual Additions	791	1,482	962	1,097	1,214	1,311	1,419	1,507	1,277	1,418	1,498	1,535	1,800	1,263	1,397	2,296	1,548	2,386	1,354	1,477		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-13		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	-	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	4	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	40	-	-	51
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	4
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	27	44	-	-	88
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	61	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	499	759
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	127
	DSM, Class 2 Total	69	67	61	59	59	57	57	52	52	51	39	42	39	38	37	35	33	32	32	30	586	945
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	36	151	248	19	162	257	-	134	255	298	40	40	297	300	277	62	126
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	22	22	22	23	22	23	26	26	22	285	516
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	28	28	28	29	27	28	30	30	26	365	646
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	268	297	297	297	297	297	297	297	238	297	297	297	156	254	297	297	297	256	264
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	215	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	166	259	307
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	191	151	140	117	96	96	141	90	942	302	83	172	1,400	77	528	122	493		
	Annual Additions, Short Term Resources	650	709	845	983	1,102	1,208	1,323	1,420	1,191	1,334	1,429	1,113	1,306	1,427	1,470	1,071	1,169	1,469	1,472	1,240		
	Total Annual Additions	791	1,486	966	1,174	1,253	1,348	1,440	1,516	1,287	1,475	1,519	2,055	1,608	1,510	1,642	2,471	1,246	1,997	1,594	1,733		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-14		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	-	-	-	-	(416)	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	-	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	736	-	736	-	-	-	-	-	736	-	2,208
	CCCT J 1x1	-	-	-	-	-	-	411	1,269	834	-	423	-	-	-	-	-	-	-	-	-	2,514	2,937
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	74	35	33	12	-	-	44	4	-	-	-	-	-	-	-	-	-	198	202
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	566	-	-	398	236	-	-	-	-	-	-	-	566	1,200
	Total Wind	-	-	-	74	35	33	12	-	566	44	4	398	236	-	-	-	-	-	-	-	764	1,402
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	6	6	6	2	3	3	3	3	1	1	1	2	1	1	1	1	1	1	45	58
	DSM, Class 2, UT	84	76	70	73	71	44	42	41	41	39	13	13	10	11	10	13	11	9	8	7	580	687
	DSM, Class 2, WY	24	24	24	24	25	3	3	2	3	2	2	2	1	2	2	2	2	1	1	1	136	153
	DSM, Class 2 Total	114	106	101	103	102	50	48	47	46	44	17	16	13	14	13	16	14	12	11	10	761	898
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.2	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	60	171	-	131	-	56	49	-	73	53	136	40	40	249	287	72	42	71
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	719	1,081
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	5	-	40
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	1	0	0	0	15	19
	DSM, Class 2, OR	37	41	34	33	30	28	24	21	19	19	21	20	20	20	20	20	20	20	20	20	285	484
	DSM, Class 2, WA	13	12	13	14	14	6	6	6	6	6	2	2	2	2	2	2	2	1	1	1	96	112
	DSM, Class 2 Total	52	55	49	49	46	35	31	28	26	26	23	22	22	22	22	22	22	21	22	22	395	615
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	54	28	82	297	297	297	297	203	297	297	156	297	229	297	13	131	297	297	10	185	194
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	107	75	200	236	375	375	331	375	375	375	375	375	375	375	375	375	375	375	375	375	282	329
	Existing Plant Retirements/Conversions	-	-	(164)	8	(378)	-	-	(1,258)	(779)	-	(261)	(450)	-	(459)	-	(760)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	192	822	167	244	201	133	516	1,358	1,488	131	484	1,189	288	789	52	1,377	52	50	85	867		
	Annual Additions, Short Term Resources	607	629	728	818	1,232	1,343	1,128	1,303	1,078	1,228	1,221	1,031	1,245	1,157	1,308	928	1,046	1,421	1,459	957		
	Total Annual Additions	799	1,451	895	1,062	1,433	1,476	1,644	2,661	2,566	1,359	1,705	2,220	1,533	1,946	1,360	2,305	1,098	1,471	1,544	1,824		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-15		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	362	-	362	-	-	-	905
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	SCCT Frame WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	515	-	-	-	-	-	515
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	74	35	33	12	-	-	44	4	-	-	-	-	-	-	-	-	-	198	202
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	398	236	-	-	-	-	-	-	-	-	634
	Total Wind	-	-	-	74	35	33	12	-	-	44	4	398	236	-	-	-	-	-	-	-	198	836
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.8	2.7	2.7	2.7	0.4	3.6	14.8
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	37	40	-	4	-	-	-	-	-	81
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	19	3	-	-	-	-	-	-	22
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	37	90	3	4	-	4	-	-	-	138
	DSM, Class 2, ID	6	6	6	6	6	2	2	2	2	3	1	1	1	2	1	1	1	1	1	1	39	52
	DSM, Class 2, UT	81	74	68	65	63	39	37	37	37	37	12	11	9	10	9	12	10	9	8	6	537	634
	DSM, Class 2, WY	23	23	23	23	24	2	2	2	2	2	2	2	1	2	2	2	2	1	1	1	128	144
	DSM, Class 2 Total	111	103	97	94	92	43	41	41	41	42	16	14	11	13	12	15	13	12	11	9	704	831
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	6	115	-	56	171	231	215	272	269	270	230	272	300	283	18	135
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	384	-	-	-	565
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	5	-	50
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	-	-	0.5
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	2
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	-	22
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	2
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	42	1	-	-	-	1	-	-	-	44
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	0	0	0	0	13	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	19	17	17	18	17	18	17	19	19	19	19	19	17	274	455
	DSM, Class 2, WA	12	12	12	12	12	5	5	5	5	5	2	1	1	1	1	2	1	1	1	1	86	99
	DSM, Class 2 Total	51	55	47	46	43	32	28	24	23	23	20	19	19	19	20	21	21	21	21	18	373	571
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	-	56	174	297	297	196	297	297	297	297	297	297	297	297	297	297	297	132	214
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	135	160	262	370	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	333	366
	FOT MidColumbia Q3 - 2	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	188	818	163	232	189	122	96	80	80	126	56	448	543	140	234	934	234	803	95	307		
	Annual Additions, Short Term Resources	610	635	737	845	931	1,049	1,178	1,287	1,071	1,228	1,343	1,403	1,387	1,444	1,441	1,442	1,402	1,444	1,472	1,455		
	Total Annual Additions	798	1,453	900	1,077	1,120	1,171	1,274	1,367	1,151	1,354	1,399	1,851	1,930	1,584	1,675	2,376	1,636	2,247	1,567	1,762		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-16	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	-	-	-	-	-	115
	Wind, GO, 29	-	-	-	-	63	-	-	-	-	63	-	-	-	-	-	-	-	-	-	-	126	126
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	446	-	-	-	-	-	-	-	-	446
	Total Wind	-	-	-	-	63	-	-	-	-	63	-	-	446	-	-	-	-	-	-	-	126	572
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	13
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	0	-	-	102	-	-	-	-	-	-	102
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	2	2	2	2	2	30	54
	DSM, Class 2, UT	63	59	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	493	751
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	55	123
	DSM, Class 2 Total	69	65	61	59	57	56	54	52	52	51	39	42	39	38	37	33	31	30	30	29	578	927
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	20	138	235	7	150	244	263	298	291	300	40	40	116	170	296	55	130
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	25	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	25	30
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	22	21	-	-	-	-	-	-	44
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	16	-	22	22	-	-	-	-	-	-	61
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	20	23	22	22	22	22	18	18	18	18	18	280	484
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	104
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	27	28	27	27	27	28	22	22	22	22	22	358	605
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	89	209	297	297	297	297	297	297	297	297	297	297	163	266	297	297	297	178	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	211	347	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	354
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	774	121	142	176	104	99	95	95	157	84	102	709	224	205	1,394	70	730	68	68		
	Annual Additions, Short Term Resources	650	711	847	964	1,084	1,192	1,310	1,407	1,179	1,322	1,416	1,435	1,470	1,463	1,472	1,078	1,181	1,288	1,342	1,468		
	Total Annual Additions	790	1,485	968	1,106	1,260	1,296	1,409	1,502	1,274	1,479	1,500	1,537	2,179	1,687	1,677	2,472	1,251	2,018	1,410	1,536		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-17		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	846	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	74	35	33	12	-	-	44	4	-	-	-	-	-	-	-	-	-	198	202
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	398	236	566	-	-	-	-	-	-	-	1,200
	Total Wind	-	-	-	74	35	33	12	-	-	44	4	398	236	566	-	-	-	-	-	-	198	1,402
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	37	-	-	-	74
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	13
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	0	50	37	-	-	-	88
	DSM, Class 2, ID	3	3	3	4	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	34	62
	DSM, Class 2, UT	68	61	57	55	53	51	48	44	44	42	31	34	31	29	28	27	25	22	21	20	523	791
	DSM, Class 2, WY	4	4	5	5	6	7	7	7	7	8	7	7	7	7	8	7	7	7	8	8	60	133
	DSM, Class 2 Total	74	68	65	64	63	62	59	55	55	53	41	44	40	40	39	37	35	32	32	31	616	987
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	49	-	-	46	94	278	53	53	300	300	259	298	253	5	99
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	9	-	-	78	-	147
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	9	-	-	78	-	147
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	5	-	40
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	21	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	27	22	-	-	-	-	52
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	11	21
	DSM, Class 2, OR	37	41	34	36	33	31	28	24	24	26	26	26	26	26	26	26	26	26	26	26	314	570
	DSM, Class 2, WA	8	8	8	8	8	7	7	7	7	7	5	5	5	5	5	4	4	3	3	3	74	118
	DSM, Class 2 Total	46	50	43	45	42	39	36	32	32	34	32	32	31	32	32	30	30	30	30	30	399	709
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	163	125	238	289	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	260	278
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	383	400	400	400	329	400	400	400	400	400	400	400	400	333	400	400	400	400	400	400	391	392
	FOT MidColumbia Q3 - 2	-	79	97	179	-	29	139	184	-	138	183	163	168	-	59	180	202	186	164	165	85	116
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	146	778	126	201	579	148	121	102	103	148	94	490	324	1,316	90	594	163	962	113	341		
	Annual Additions, Short Term Resources	646	704	835	968	726	826	936	1,030	797	935	1,026	1,054	1,243	783	909	1,277	1,299	1,242	1,259	1,215		
	Total Annual Additions	792	1,482	961	1,169	1,305	974	1,057	1,132	900	1,083	1,120	1,544	1,567	2,099	999	1,871	1,462	2,204	1,372	1,556		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-3 Case C-18		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	(479)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	WY IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	456	-	456
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	423	834	411	-	-	-	2,091
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	2,236	-	-	-	-	-	-	-	-	2,236
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	Wind, GO, 29	-	-	-	-	-	-	-	-	-	346	47	63	76	68	-	-	-	-	-	-	346	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
	Wind, Wyoming, 40	-	-	-	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	-	-	-	1,200	1,200
	Total Wind	-	-	-	-	-	-	-	1,200	-	346	247	63	76	68	-	-	-	-	-	-	1,546	2,000
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	8	8	7	3	3	3	3	3	1	1	1	2	2	2	1	1	1	1	51	65
	DSM, Class 2, UT	88	81	83	81	80	51	49	43	42	40	14	13	11	12	11	14	11	10	9	8	639	750
	DSM, Class 2, WY	25	25	25	26	26	3	3	3	3	3	3	2	2	2	2	2	2	2	1	1	141	159
	DSM, Class 2 Total	120	112	115	115	114	58	55	48	48	46	18	17	13	15	14	17	15	13	11	10	830	973
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	450	-	-	-	-	-	-	-	450
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.4	13.4	13.4	131	263
	Micro Solar - Water Heating	-	-	-	0.4	0.3	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	118	-	40	-	-	-	53	53	293	53	53	78	53	16	40
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	-	-	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	360	722
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	360	240	-	-	-	-	-	-	-	-	-	600
	Total Wind	-	-	-	-	-	-	-	-	-	-	360	240	-	-	-	-	-	-	-	-	-	600
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	1	0	0	1	1	1	1	1	1	0	16	22
	DSM, Class 2, OR	41	44	40	38	34	31	28	25	23	23	22	21	21	21	21	21	21	21	21	21	327	535
	DSM, Class 2, WA	14	14	14	14	14	7	7	6	6	6	2	2	2	3	3	3	2	2	2	2	104	127
	DSM, Class 2 Total	57	60	56	55	51	38	36	33	30	30	25	24	24	24	24	24	24	23	23	23	447	684
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	99	33	-	78	108	196	297	297	190	297	81	250	-	-	120	297	-	188	297	61	160	144
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	-	81	196	206	240	255	266	375	375	375	375	375	4	343	375	375	345	375	375	375	237	284
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	(158)	-	(3)	8	(269)	(1,208)	(416)	-	(760)	-	(543)	(148)	-		
	Annual Additions, Long Term Resources	203	832	189	187	183	111	106	1,296	95	439	1,089	495	2,366	574	54	481	889	464	51	506		
	Annual Additions, Short Term Resources	599	614	696	784	848	951	1,063	1,290	1,065	1,212	956	1,125	504	896	1,048	1,465	898	1,116	1,250	989		
	Total Annual Additions	802	1,446	885	971	1,031	1,062	1,169	2,586	1,160	1,651	2,045	1,620	2,870	1,470	1,102	1,946	1,787	1,580	1,301	1,495		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-3 Case C-19	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	74	35	33	12	-	-	44	4	-	-	-	-	-	-	-	-	-	198	202
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	398	236	-	-	-	-	-	-	-	-	634
	Total Wind	-	-	-	74	35	33	12	-	-	44	4	398	236	-	-	-	-	-	-	-	198	836
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	4	77	-	-	-	-	-	-	-	85
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	13	-	9	-	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	5	17	77	40	-	-	-	-	-	-	139
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	2	3	2	2	2	30	55
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	21	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	7	55	123
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	34	33	30	30	29	581	932
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	157	254	26	167	261	262	207	49	142	199	300	250	273	265	64	143
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	197
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	78	-	78
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35	5	-	40
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	26	1	45	-	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	18	19	18	18	18	283	487
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	22	23	22	22	22	361	610
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	108	229	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	333	333	352
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	191	148	137	112	95	96	141	88	515	997	385	121	919	72	911	103	348		
	Annual Additions, Short Term Resources	650	709	845	983	1,104	1,211	1,329	1,426	1,198	1,339	1,433	1,434	1,379	1,221	1,314	1,371	1,472	1,422	1,445	1,395		
	Total Annual Additions	790	1,485	966	1,174	1,252	1,348	1,441	1,521	1,294	1,480	1,521	1,949	2,376	1,606	1,435	2,290	1,544	2,333	1,548	1,743		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.10 – Energy Gateway Scenario 4 – Case C-01 to C-19

	EG-4 Case C-01	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	IC Aero WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	91
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	3.6	7.6
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	41	4	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	0	-	-	45	-	-	-	63	34	14	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	56	125
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	31	581	938
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	169	263	67	262	300	88	262	283	300	299	300	65	154
West	**Expansion Resources**																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	8	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	21	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	2	-	15
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	2	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	24	14	26	-	103
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	19	22	22	22	26	26	283	509
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	24	26	26	26	30	30	361	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	378	389
	FOT MidColumbia Q3 - 2	375	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	355	365
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	100	95	96	98	84	747	82	166	500	738	167	835	126	209		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,341	1,435	1,239	1,434	1,472	1,260	1,434	1,455	1,472	1,471	1,472		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,431	1,523	1,295	1,439	1,519	1,986	1,516	1,638	1,760	2,172	1,622	2,307	1,597	1,681		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-02	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	661	661	-	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	46	29	13	-	-	44	-	-	-	-	-	-	-	-	-	-	202	202
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	544	-	-	-	-	-	-	-	-	544
	Total Wind	-	-	-	70	46	29	13	-	-	44	-	-	544	-	-	-	-	13	-	-	202	759
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	48	-	41	-	-	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	8	7	-	7	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	10	13	-	-	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	2
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	-	0	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	19	72	-	54	-	-	-	-	-	144
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	2	2	2	2	30	55
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	21	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	55	124
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	31	30	30	29	581	931
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	39	157	254	26	169	263	140	300	300	202	300	40	164	218	208	65	139
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	197
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	8	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	13	49	-	22	-	-	-	-	-	84
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	21	23	22	22	22	22	22	18	18	18	18	282	489
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	28	28	27	27	27	28	26	22	22	22	22	359	611
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	297	87	297	297	297	182	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	370	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	365	358	377
	FOT MidColumbia Q3 - 2	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	(387)	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	187	159	133	113	95	96	140	84	267	658	203	742	815	731	505	68	265		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,211	1,329	1,426	1,198	1,341	1,435	1,312	1,472	1,472	1,374	1,472	1,002	1,336	1,390	1,345		
	Total Annual Additions	790	1,485	966	1,171	1,263	1,344	1,442	1,521	1,294	1,481	1,519	1,579	2,130	1,675	2,116	2,287	1,733	1,841	1,458	1,610		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-4 Case C-03		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	634	-	-	-	-	634
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	661
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	713	-	-	-	-	-	-	-	-	713
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	34	13	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	12	-	25
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	684	-	-	-	-	-	-	-	-	684
	Total Wind	-	-	-	73	34	34	13	-	-	45	5	-	684	-	-	-	-	13	-	12	199	913
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	5	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	4	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	23	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	10	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	102	17	-	-	-	37	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	47	45	43	42	40	30	33	30	28	27	25	23	22	21	20	494	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	67	61	59	57	55	55	52	52	51	39	42	39	38	37	35	33	32	31	30	580	935
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	40	158	255	27	169	263	255	168	290	298	298	40	182	232	300	65	149
West	**Expansion Resources**																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	6
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	22	-	-	21	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	41	-	-	23	-	-	-	-	16	-	80
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	22	22	22	22	19	19	22	24	282	499
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	26	29	28	27	27	27	28	26	23	23	26	28	360	622
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	297	108	297	297	297	182	230
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	370	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	358	379
	FOT MidColumbia Q3 - 2	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	147	137	113	95	95	141	89	129	1,479	81	206	936	706	507	73	140		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,212	1,330	1,427	1,199	1,341	1,435	1,427	1,340	1,462	1,470	1,470	1,023	1,354	1,404	1,472		
	Total Annual Additions	790	1,485	966	1,174	1,251	1,349	1,443	1,522	1,294	1,482	1,524	1,556	2,819	1,543	1,676	2,406	1,729	1,861	1,477	1,612		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-04	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	-	-	661	-	-	-	-	-	-	-	-	-	-	-	-	1,322	1,322
	CCCT GH 2x1	-	-	-	-	-	-	736	-	-	736	-	-	-	-	-	-	-	736	-	-	1,472	2,208
	CCCT J 1x1	-	-	-	-	-	-	-	-	846	423	-	411	-	-	423	-	-	-	-	-	1,269	2,103
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	27	47
	DSM, Class 2, UT	63	55	51	48	49	47	44	40	40	35	27	32	29	27	26	25	23	22	21	20	471	723
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	6	7	7	7	7	7	7	55	122
	DSM, Class 2 Total	68	62	58	56	57	55	53	49	50	45	35	40	37	36	35	33	32	31	30	29	553	892
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	182	68	177	-	253	261	117	216	-	112	238	40	101	204	62	116	241	117	125
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	17	17	17	17	18	18	18	18	19	19	19	273	454
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	65	101
	DSM, Class 2 Total	45	48	41	40	38	33	29	25	24	24	22	22	22	23	23	22	22	23	22	22	347	572
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	202	297	297	297	297	212	297	297	297	297	297	297	297	297	243	266
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	82	100	100	100	100	100	100	99
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	269	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(927)	(1,047)	(788)	8	-	-	-	-	-	-	(495)	(74)	-		
	Annual Additions, Long Term Resources	140	770	117	113	774	103	832	752	937	1,244	74	490	75	76	498	72	71	806	69	68		
	Annual Additions, Short Term Resources	651	714	1,223	1,354	1,240	1,349	1,077	1,425	1,433	1,289	1,388	1,087	1,284	1,410	1,194	1,273	1,376	1,234	1,288	1,413		
	Total Annual Additions	791	1,484	1,340	1,467	2,014	1,452	1,909	2,177	2,370	2,533	1,462	1,577	1,359	1,486	1,692	1,345	1,447	2,040	1,357	1,481		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-4 Case C-05		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	661	661	661	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	736	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	736	1,472
	CCCT J 1x1	-	-	-	-	-	-	-	411	423	423	411	-	-	-	-	-	-	423	-	-	1,257	2,091
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	2	2	2	2	2	2	2	28	50
	DSM, Class 2, UT	63	55	51	48	49	47	44	40	40	40	30	33	30	27	26	25	23	22	21	20	477	734
	DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	6	7	7	7	7	7	7	55	122
	DSM, Class 2 Total	68	62	58	56	57	55	53	49	50	51	39	42	39	36	35	33	32	30	30	29	560	906
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	181	-	108	140	225	175	128	79	108	300	34	40	40	99	112	165	291	107	117
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	20	19	19	18	18	18	18	18	19	19	275	463
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	66	102
	DSM, Class 2 Total	45	49	41	40	38	33	29	26	24	26	25	24	24	23	23	22	22	22	22	22	350	582
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	297	297	297	297	297	83	275	254	297	297	297	297	252	261
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	67	-	100	100	100	100	100	100	93
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(548)	(1,010)	(1,237)	(183)	(212)	-	-	-	-	-	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	117	187	884	137	770	1,164	1,175	563	498	515	297	812	75	72	71	492	69	68		
	Annual Additions, Short Term Resources	651	714	1,222	1,353	1,172	1,280	1,312	1,397	1,347	1,300	1,251	1,280	1,472	959	1,090	1,169	1,271	1,284	1,337	1,463		
	Total Annual Additions	791	1,485	1,339	1,540	2,056	1,417	2,082	2,561	2,522	1,863	1,749	1,795	1,769	1,771	1,165	1,241	1,342	1,776	1,406	1,531		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-4 Case C-06		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	2	3	3	3	3	3	3	3	32	59
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	508	767
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	6	7	7	7	7	7	7	7	56	126
	DSM, Class 2 Total	73	67	61	60	59	61	58	53	52	51	40	43	38	38	37	35	33	32	31	30	596	952
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	28	142	237	6	148	241	263	40	40	147	201	300	57	107	230	56	109
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	11
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	22	19	19	19	22	22	22	22	22	295	507
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	3	3	3	3	3	71	110
	DSM, Class 2 Total	45	49	42	41	40	35	32	31	30	30	29	28	25	24	24	26	26	26	26	26	376	635
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	243	258	297	297	297	297	297	297	297	297	145	269	297	297	297	297	297	297	254	266
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	220	300	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	117	111	105	98	99	98	85	100	740	79	78	923	75	1,158	73	73		
	Annual Additions, Short Term Resources	646	705	841	978	1,097	1,200	1,314	1,409	1,178	1,320	1,413	1,435	1,060	1,184	1,319	1,373	1,472	1,229	1,279	1,402		
	Total Annual Additions	791	1,482	962	1,097	1,214	1,311	1,419	1,507	1,277	1,418	1,498	1,535	1,800	1,263	1,397	2,296	1,547	2,387	1,352	1,475		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-07	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	846	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	436	218	-	-	-	-	-	-	-	-	654
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	436	218	-	-	-	-	-	-	-	202	862
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	81	-	-	-	-	-	-	-	81
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	2
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	81	-	-	-	-	2	0	-	84
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	32	61
	DSM, Class 2, UT	67	61	55	52	50	51	48	43	42	40	30	33	30	28	27	25	24	22	22	20	510	770
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	7	7	8	7	7	7	8	8	56	129
	DSM, Class 2 Total	73	67	62	60	60	61	58	53	52	51	40	43	39	38	37	35	34	32	32	31	598	960
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	24	138	233	3	144	237	263	298	291	266	90	176	156	205	166	54	135
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	-	-	-	-	197
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	3	-	45	-	-	-	4	1	-	-	53
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	23	23	26	22	23	23	26	26	26	295	536
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	4	4	3	3	3	71	114
	DSM, Class 2 Total	45	49	42	41	40	36	32	31	30	30	29	29	29	32	28	28	28	30	30	29	377	668
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	242	263	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	254	276
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	97	214	297	375	375	375	375	375	375	375	375	375	361	364	375	370	365	366	258	314
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	122	192	153	145	118	99	99	144	91	529	484	212	279	1,163	78	929	81	258		
	Annual Additions, Short Term Resources	646	705	839	977	1,094	1,196	1,310	1,405	1,175	1,316	1,409	1,435	1,470	1,463	1,424	1,251	1,348	1,323	1,367	1,329		
	Total Annual Additions	791	1,482	961	1,169	1,247	1,341	1,428	1,504	1,274	1,460	1,500	1,964	1,954	1,675	1,703	2,414	1,426	2,252	1,448	1,587		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-4 Case C-08		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	1,322	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	736	-	-	-	-	-	-	736	-	-	-	-	-	-	736	1,472
	CCCT J 1x1	-	-	-	-	-	-	-	846	423	-	411	-	-	-	-	-	-	411	423	-	1,269	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	55	54	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	483	742
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	51	39	42	39	38	37	35	33	32	31	30	567	922
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	176	61	160	-	16	-	71	64	96	290	34	33	40	75	93	61	61	59	72
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	19	19	19	19	22	22	22	22	22	22	275	485
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	24	26	25	24	24	24	27	26	26	26	26	26	352	606
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	184	297	227	297	297	297	297	138	265	297	297	297	32	155	234	236
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	-	-	36	100	100	100	100	100	87
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(1,279)	(279)	(816)	(548)	-	(268)	-	-	-	-	-	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	117	774	1,425	832	937	514	94	491	83	79	814	80	78	76	485	497	73		
	Annual Additions, Short Term Resources	651	714	1,219	1,348	1,233	1,332	1,059	1,188	1,102	1,243	1,236	1,268	1,462	947	1,073	1,148	1,247	1,265	968	1,091		
	Total Annual Additions	791	1,485	1,339	1,465	2,007	2,757	1,891	2,125	1,616	1,337	1,727	1,351	1,541	1,761	1,153	1,226	1,323	1,750	1,465	1,164		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-09	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_UT - Gas RePower	-	-	-	-	-	-	468	-	-	-	-	-	-	-	-	-	-	-	-	-	468	468
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	661	661	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	-	846	423	411	411	-	-	-	423	-	-	-	-	-	1,680	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	83	-	-	-	-	-	-	-	83
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	83	-	-	-	-	-	-	202	941
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	27	55
	DSM, Class 2, UT	63	55	51	51	49	47	44	40	40	39	30	33	30	28	27	25	23	22	21	20	479	737
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	62	58	59	57	55	53	49	50	49	39	42	39	38	37	35	33	32	31	30	561	917
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	112	178	64	235	21	150	64	-	-	-	177	300	82	159	258	40	61	145	82	102
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	19	19	19	19	19	19	22	22	22	23	275	479
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	66	103
	DSM, Class 2 Total	45	49	41	40	38	33	29	26	24	26	25	24	24	24	24	23	26	26	26	27	351	599
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	297	260	254	283	297	297	297	297	297	231	260	297	249	265
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(714)	(270)	(816)	(548)	(106)	(268)	-	-	-	-	-	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	117	190	809	798	770	938	514	549	497	515	297	161	500	74	75	810	74	74		
	Annual Additions, Short Term Resources	651	714	1,222	1,350	1,236	1,407	1,193	1,322	1,236	1,135	1,129	1,158	1,349	1,472	1,254	1,331	1,430	1,146	1,196	1,317		
	Total Annual Additions	791	1,485	1,339	1,540	2,045	2,205	1,963	2,260	1,750	1,684	1,626	1,673	1,646	1,633	1,754	1,405	1,505	1,956	1,270	1,391		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-4 Case C-10		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	661	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	411	-	-	-	-	-	-	411
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	48	-	37	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	15	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	19	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	-	-	16	-	-	67	0	48	25	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	31	30	581	937
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	170	263	67	262	298	94	268	299	299	299	300	65	155
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	ICE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	-	-	-	117
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	70	-	-	1	1	-	16	-	88
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	22	22	22	22	22	22	25	26	282	511
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	106
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	29	28	27	27	28	27	26	26	26	30	30	360	635
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	378	389
	FOT MidColumbia Q3 - 2	375	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	355	365
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	100	95	96	96	85	747	82	168	492	739	144	853	125	208		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,342	1,435	1,239	1,434	1,470	1,266	1,440	1,471	1,471	1,471	1,472		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,431	1,523	1,295	1,438	1,520	1,986	1,516	1,638	1,758	2,179	1,615	2,324	1,596	1,680		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-11	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	6.6	6.6	7.9	7.9	7.9	-	44.8
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	2.7	2.7	2.7	2.7	2.7	2.7	3.7	3.7	3.6	28.3
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	40	4	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	45	97	4	-	-	0	11	-	158
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	61
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	29	28	27	24	23	22	22	508	776
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	8	7	7	7	7	8	7	7	7	8	8	57	131
	DSM, Class 2 Total	73	67	61	61	59	61	58	53	52	52	40	43	39	39	39	37	34	33	33	33	597	967
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	26	138	233	3	143	237	263	294	293	300	300	295	298	300	300	54	171
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	IC Aero WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	99	-	198
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	5	-	25
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	1.1	0.9	2.3	2.3	2.3	-	11.3
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	-	2.7
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	13	2	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	71	13	-	14	-	13	5	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 2, OR	37	41	33	32	29	28	27	23	23	23	23	26	26	26	26	26	26	26	26	26	296	550
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	5	5	5	5	4	4	4	4	4	69	112
	DSM, Class 2 Total	46	49	41	41	38	35	34	30	30	30	29	32	31	32	32	31	30	30	30	31	375	683
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	102	221	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	171	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	377	389
	FOT MidColumbia Q3 - 2	375	204	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	354	365
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	192	150	144	121	99	99	144	91	525	489	206	210	940	196	853	128	214		
	Annual Additions, Short Term Resources	646	704	840	977	1,096	1,198	1,310	1,405	1,175	1,315	1,409	1,435	1,466	1,465	1,472	1,472	1,467	1,470	1,472	1,472		
	Total Annual Additions	791	1,481	961	1,169	1,246	1,342	1,431	1,504	1,274	1,459	1,500	1,960	1,955	1,671	1,682	2,412	1,663	2,323	1,600	1,686		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-12	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	**10-year**	**20-year**
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423	-	423	-	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	2	2	3	3	3	3	3	3	3	30	57
	DSM, Class 2, UT	63	56	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	494	752
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	56	125
	DSM, Class 2 Total	69	63	61	59	59	57	57	52	52	51	39	42	38	38	37	35	33	32	31	30	580	934
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	42	157	254	25	169	263	-	152	276	64	240	40	98	149	271	65	110
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	19	19	19	19	19	19	22	22	22	285	488
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	3	3	3	3	3	71	109
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	25	24	24	24	23	23	26	26	26	365	615
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	134	251	267	297	297	297	297	297	297	297	251	297	297	297	297	252	297	297	297	257	272
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	311	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	121	118	116	106	103	95	96	95	84	506	79	79	501	735	495	735	73	73		
	Annual Additions, Short Term Resources	650	713	849	988	1,108	1,214	1,329	1,426	1,197	1,341	1,435	1,126	1,324	1,448	1,236	1,412	1,167	1,270	1,321	1,443		
	Total Annual Additions	791	1,485	970	1,106	1,224	1,320	1,432	1,521	1,293	1,436	1,519	1,632	1,403	1,527	1,737	2,147	1,662	2,005	1,394	1,516		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-13	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	43	-	-	-	-	-	693
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	43	-	-	-	-	202	901
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	2.7	0.4	0.5	2.7	0.4	3.6	12.5
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	-	-	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	145	-	-	-	-	-	146
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	32	61
	DSM, Class 2, UT	67	61	55	52	53	51	48	43	42	40	30	33	30	29	28	27	24	22	22	20	513	777
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	8	7	7	7	7	8	7	7	7	8	7	57	130
	DSM, Class 2 Total	73	67	62	60	63	61	58	53	52	52	40	43	39	39	39	37	34	33	32	31	602	968
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	22	135	230	-	140	234	262	106	224	300	300	240	256	300	295	53	152
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	IC Aero SO-CAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	IC Aero WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	-	-	99
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	-	0.3
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	51	22	-	-	-	-	-	73
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	26	26	26	26	26	26	26	26	22	295	545
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	4	4	3	3	3	71	114
	DSM, Class 2 Total	45	50	42	41	40	36	32	31	30	30	29	32	31	32	32	31	30	30	30	26	377	679
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	242	262	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	254	275
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	97	214	294	375	375	375	375	375	375	375	375	375	375	375	375	375	375	147	258	305
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	122	192	156	145	118	99	99	145	91	523	728	87	140	958	262	839	82	493		
	Annual Additions, Short Term Resources	646	705	839	976	1,091	1,194	1,307	1,402	1,172	1,312	1,406	1,434	1,278	1,396	1,472	1,472	1,412	1,428	1,472	1,239		
	Total Annual Additions	791	1,482	961	1,168	1,247	1,339	1,425	1,501	1,271	1,457	1,497	1,957	2,006	1,483	1,612	2,430	1,674	2,267	1,554	1,732		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-14	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	-	-	-	-	-	(416)	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	-	634	-	-	-	-	-	-	-	-	-	634
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	1,322	-	-	-	-	-	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	423	1,680	-	423	411	-	-	-	-	-	-	-	-	-	2,526	2,937
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	34	13	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	316	-	-	-	684	-	-	-	-	-	-	-	316	1,000
	Total Wind	-	-	-	73	34	34	13	-	316	45	5	-	684	-	-	-	-	13	-	-	515	1,217
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	6	6	6	2	3	3	3	3	1	1	1	2	1	1	1	1	1	1	45	58
	DSM, Class 2, UT	84	76	70	73	71	44	42	35	41	39	13	13	10	11	10	13	11	9	8	7	575	681
	DSM, Class 2, WY	24	24	24	24	25	3	3	2	3	2	2	2	1	2	2	2	2	1	1	1	136	153
	DSM, Class 2 Total	114	106	101	103	102	50	48	41	46	44	17	16	13	14	13	16	14	12	11	10	755	891
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.2	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	60	171	-	157	249	52	55	-	169	148	299	40	40	2	53	61	69	78
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	719	1,081
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	1	1	0	0	15	19
	DSM, Class 2, OR	37	41	34	33	30	28	24	21	19	20	21	20	20	20	20	20	20	20	20	20	285	485
	DSM, Class 2, WA	13	12	13	14	14	6	6	6	6	6	2	2	2	2	2	2	2	1	1	1	96	112
	DSM, Class 2 Total	52	55	49	49	46	35	31	28	26	26	23	22	22	22	22	22	22	21	22	22	396	616
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	54	28	82	297	297	297	297	297	297	297	256	297	297	297	176	294	68	86	221	195	212
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	107	75	200	236	375	375	321	375	375	375	375	375	375	375	375	375	375	375	375	375	281	328
	Existing Plant Retirements/Conversions	-	-	(164)	8	(378)	-	-	(1,674)	(363)	-	(261)	(450)	-	(459)	-	(760)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	192	822	167	243	200	134	529	1,763	404	555	473	689	736	714	51	1,376	52	799	50	48		
	Annual Additions, Short Term Resources	607	629	728	818	1,232	1,343	1,118	1,329	1,421	1,224	1,227	1,131	1,341	1,320	1,471	1,091	1,209	945	1,014	1,157		
	Total Annual Additions	799	1,451	895	1,061	1,432	1,477	1,647	3,092	1,825	1,779	1,700	1,820	2,077	2,034	1,522	2,467	1,261	1,744	1,064	1,205		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-15	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	362	-	362	-	-	-	905
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	SCCT Frame WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	515	-	-	-	-	-	515
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	34	13	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	684	-	-	-	-	-	-	-	-	684
	Total Wind	-	-	-	73	34	34	13	-	-	45	5	-	684	-	-	-	-	13	-	-	199	901
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	2.7	2.7	2.7	0.4	0.4	3.6	14.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	4	-	-	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	19	3	-	-	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	3	19	-	-	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	0	-	97	37	3	4	-	4	-	-	-	145
	DSM, Class 2, ID	6	6	6	6	6	2	2	2	2	3	1	1	1	2	1	1	1	1	1	1	39	52
	DSM, Class 2, UT	81	74	68	65	63	39	37	37	37	37	12	11	9	10	9	12	11	9	7	6	537	634
	DSM, Class 2, WY	23	23	23	23	23	2	2	2	2	2	2	2	1	2	2	2	2	1	1	1	128	144
	DSM, Class 2 Total	111	103	97	94	92	43	41	41	41	42	16	14	11	13	12	15	14	12	10	9	704	830
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	7	115	-	56	171	235	190	300	298	297	257	300	215	284	18	136
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	203	-	-	-	384
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	8
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	1	-	-	-	8
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	0	0	0	0	12	16
	DSM, Class 2, OR	36	41	33	32	29	26	22	19	17	17	18	17	18	17	17	19	19	19	17	17	274	451
	DSM, Class 2, WA	12	12	12	12	12	5	5	5	5	5	2	1	1	1	1	2	1	1	1	1	86	98
	DSM, Class 2 Total	51	55	47	46	43	32	28	24	23	23	20	19	19	19	19	21	21	20	18	18	372	565
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	-	57	175	297	297	197	297	297	297	297	297	297	297	297	297	297	297	132	215
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	135	160	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	350	375
	FOT MidColumbia Q3 - 2	375	375	237	346	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	358	367
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	188	818	163	231	187	123	97	80	80	126	57	50	1,016	86	232	936	234	815	225	134		
	Annual Additions, Short Term Resources	610	635	737	846	932	1,050	1,179	1,287	1,072	1,228	1,343	1,407	1,362	1,472	1,470	1,469	1,429	1,472	1,387	1,456		
	Total Annual Additions	798	1,453	900	1,077	1,119	1,173	1,276	1,367	1,152	1,354	1,400	1,457	2,378	1,558	1,702	2,405	1,663	2,287	1,612	1,590		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-16	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	-	-	-	-	-	115
	Wind, GO, 29	-	-	-	-	63	-	-	-	-	63	-	-	-	-	-	-	-	-	-	-	126	126
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	446	-	-	-	-	-	-	-	-	446
	Total Wind	-	-	-	-	63	-	-	-	-	63	-	-	446	-	-	-	-	-	-	-	126	572
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	0	-	-	116	-	-	-	-	-	-	116
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	2	2	2	2	2	30	54
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	56	123
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	33	31	30	30	29	581	930
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	18	136	233	4	145	237	263	298	284	300	40	40	116	170	296	54	129
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	25	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	25	30
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	21
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	3	8	-	29	1	-	-	-	-	-	-	41
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	18	18	18	18	18	284	487
	DSM, Class 2, WA	8	7	7	7	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	104
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	27	28	22	22	22	22	22	361	609
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	87	207	297	297	297	297	297	297	297	297	297	297	163	266	297	297	297	178	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	370	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	358	379
	FOT MidColumbia Q3 - 2	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	142	176	104	100	95	96	161	87	95	709	231	198	1,394	70	730	68	68		
	Annual Additions, Short Term Resources	650	709	845	962	1,082	1,190	1,308	1,405	1,176	1,317	1,409	1,435	1,470	1,456	1,472	1,078	1,181	1,288	1,342	1,468		
	Total Annual Additions	790	1,485	966	1,104	1,258	1,294	1,408	1,500	1,272	1,478	1,496	1,530	2,179	1,687	1,670	2,472	1,251	2,018	1,410	1,536		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-17	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	846	-	-	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	34	13	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	684	316	-	-	-	-	-	-	-	1,000
	Total Wind	-	-	-	73	34	34	13	-	-	45	5	-	684	316	-	-	-	13	-	-	199	1,217
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	81	-	-	-	88
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	10	-	-	-	-	13
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	3	17	90	-	-	-	111
	DSM, Class 2, ID	3	3	3	4	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	34	62
	DSM, Class 2, UT	68	61	57	55	53	51	48	44	44	42	31	34	30	29	28	27	25	23	22	20	523	792
	DSM, Class 2, WY	4	4	5	5	6	6	7	7	7	8	7	7	7	7	8	7	7	7	8	8	59	132
	DSM, Class 2 Total	74	68	65	64	63	61	59	55	55	53	41	43	40	40	39	37	35	33	32	31	616	987
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	70	-	-	50	102	283	53	170	189	245	249	300	261	7	99
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	21	-	-	-	44
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24	-	21	-	-	-	46
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	11	21
	DSM, Class 2, OR	37	41	34	34	33	31	27	24	24	24	26	26	26	26	26	26	26	26	26	26	308	565
	DSM, Class 2, WA	8	8	8	8	8	7	7	7	7	7	5	5	5	5	5	4	4	3	3	3	74	118
	DSM, Class 2 Total	46	50	43	43	42	39	35	32	32	32	32	32	31	32	32	30	30	30	30	30	393	703
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	163	125	239	291	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	260	279
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	383	400	400	400	330	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	391	396
	FOT MidColumbia Q3 - 2	-	79	97	178	-	31	142	166	3	143	183	163	168	166	177	180	202	186	181	183	84	131
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	146	778	125	198	578	148	121	101	103	147	94	92	772	828	87	957	99	865	79	258		
	Annual Additions, Short Term Resources	646	704	836	969	727	828	939	1,033	800	940	1,030	1,062	1,248	1,016	1,144	1,166	1,244	1,232	1,278	1,241		
	Total Annual Additions	792	1,482	961	1,167	1,305	976	1,060	1,134	903	1,087	1,124	1,154	2,020	1,844	1,231	2,123	1,343	2,097	1,357	1,499		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-4 Case C-18	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	(416)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	(479)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	WY IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	456	-	456
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	834	-	-	-	1,680
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	2,236	-	-	-	-	-	-	-	-	2,236
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	Wind, GO, 29	-	-	-	-	-	-	-	-	-	-	373	62	60	105	-	-	-	-	-	-	-	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
	Wind, Wyoming, 40	-	-	-	-	-	-	-	650	350	-	-	-	-	-	-	-	-	-	-	-	1,000	1,000
	Total Wind	-	-	-	-	-	-	-	650	350	-	573	62	60	105	-	-	-	-	-	-	1,000	1,800
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	8	8	7	3	3	3	3	3	1	1	1	2	2	2	1	1	1	1	51	65
	DSM, Class 2, UT	88	81	77	81	80	51	49	43	42	40	14	13	11	12	10	14	11	10	9	8	633	743
	DSM, Class 2, WY	25	25	25	26	26	3	3	3	3	3	3	2	2	2	2	2	2	2	1	1	141	159
	DSM, Class 2 Total	120	112	109	115	114	58	55	48	48	46	18	17	13	15	14	17	15	13	12	10	824	967
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	450	-	-	-	-	-	-	-	450
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.4	13.4	13.4	131	263
	Micro Solar - Water Heating	-	-	-	0.4	0.3	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	128	-	49	143	80	-	53	53	134	250	122	190	53	18	63
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	-	-	-	-	-	-	-	362	-	-	-	-	-	-	-	-	-	-	362
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	Wind, WV, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	300
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	300
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	1	0	0	1	1	1	1	1	1	0	16	22
	DSM, Class 2, OR	41	44	40	38	34	31	28	25	23	23	22	21	21	21	21	21	21	21	21	21	327	535
	DSM, Class 2, WA	14	14	14	14	14	7	7	6	6	6	2	2	2	3	3	3	2	2	2	2	104	126
	DSM, Class 2 Total	57	60	56	55	51	38	36	33	30	30	25	24	24	24	24	24	24	23	23	23	447	684
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	99	33	-	83	113	201	297	297	197	297	297	297	-	95	248	297	297	297	297	173	162	196
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	-	81	201	206	240	255	271	375	375	375	375	375	210	375	375	375	375	375	375	375	238	298
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	(158)	-	-	8	-	(1,208)	(416)	-	(834)	-	(543)	(74)	-		
	Annual Additions, Long Term Resources	203	832	183	187	183	111	106	746	445	93	632	254	2,350	611	54	1,204	55	887	51	506		
	Annual Additions, Short Term Resources	599	614	701	789	853	956	1,068	1,300	1,072	1,221	1,315	1,252	710	1,023	1,176	1,306	1,422	1,294	1,362	1,101		
	Total Annual Additions	802	1,446	884	976	1,036	1,067	1,174	2,046	1,517	1,314	1,947	1,506	3,060	1,634	1,230	2,510	1,477	2,181	1,413	1,607		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-4 Case C-19

		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	-	-	736
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	34	13	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	13	-	-	-	23
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	684	-	-	-	-	-	-	-	-	684
	Total Wind	-	-	-	73	34	34	13	-	-	45	15	-	684	-	-	-	-	13	-	-	199	911
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	3.6	7.6
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	4	-	-	-	47	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	7	-	-	-	15	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	0	1	-	-	79	11	-	-	-	65	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	60	54	51	49	47	45	43	42	40	30	33	30	28	27	25	23	22	21	20	494	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	55	55	52	52	51	39	42	39	38	37	35	33	32	31	31	580	936
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	169	263	263	156	277	300	300	244	196	251	300	65	160
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	-	-	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	181
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	8	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	-	-	2	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	22	-	-	21	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	-	-	2	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	1	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	34	-	-	31	8	-	-	-	3	-	76
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	22	22	22	20	19	22	22	26	283	502
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	104
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	29	28	27	27	27	27	24	22	26	26	29	360	624
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	192	400	378	378
	FOT MidColumbia Q3 - 2	375	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	171	375	168	355	345
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	147	137	113	95	96	141	99	121	1,502	81	191	936	253	1,168	74	146		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,341	1,435	1,435	1,328	1,449	1,472	1,472	1,416	1,164	1,215	1,265		
	Total Annual Additions	790	1,485	966	1,174	1,252	1,350	1,444	1,523	1,295	1,482	1,534	1,556	2,830	1,530	1,663	2,408	1,669	2,332	1,289	1,411		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.11 – Energy Gateway Scenario 5 – Case C-01 to C-19

	EG-5 Case C-01	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	661	-	661	-	-	-	1,983
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	368
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	343	-	-	-	-	-	343
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	37	-	48	4	-	-	-	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	19
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	37	19	79	4	-	-	-	-	-	139
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	2	2	2	31	56
	DSM, Class 2, UT	66	61	54	51	49	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	502	761
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	126
	DSM, Class 2 Total	72	67	61	59	57	57	58	52	52	51	39	43	39	38	37	35	33	31	30	29	588	943
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	37	152	249	21	162	257	263	168	270	299	172	270	220	273	237	62	153
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	21	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	26	22	1	23	-	-	-	-	-	-	73
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	22	22	19	19	18	284	495
	DSM, Class 2, WA	8	7	7	7	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	26	26	23	23	22	361	619
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	106	227	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	172	231	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	360	380
	FOT MidColumbia Q3 - 2	375	375	342	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	372	373
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	144	776	121	117	113	104	103	95	96	98	84	114	803	102	184	1,086	76	912	69	436		
	Annual Additions, Short Term Resources	647	706	842	981	1,102	1,209	1,324	1,421	1,193	1,334	1,429	1,435	1,340	1,442	1,471	1,344	1,442	1,392	1,445	1,409		
	Total Annual Additions	791	1,482	963	1,098	1,215	1,313	1,427	1,516	1,289	1,432	1,513	1,549	2,143	1,544	1,655	2,430	1,518	2,304	1,514	1,845		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-02		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	ICE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	103	-	-	-	103
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	70	47	30	13	-	-	44	-	-	-	-	-	-	-	-	-	-	204	204
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	546	-	-	-	-	-	-	-	-	546
	Total Wind	-	-	-	70	47	30	13	-	-	44	-	-	546	-	-	-	-	-	-	-	204	750
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.6	7.9	-	14.5
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.8	2.7	2.7	3.6	12.5
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	4	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	-	-	7	-	77	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	11	7	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	10	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	5	-	-	12	13	95	11	11	12	-	158
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	59
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	22	21	495	756
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	8	8	56	127
	DSM, Class 2 Total	69	67	61	59	57	57	55	52	52	51	39	42	39	38	37	35	33	33	32	32	581	942
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	38	156	253	25	166	260	262	101	223	299	300	300	299	299	299	64	164
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55	22	-	-	-	-	77
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55	22	-	-	-	-	77
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4	1.8	-	3.2
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4	-	0.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	15	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	28	-	-	44	-	-	-	26	18	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	26	26	26	26	26	284	523
	DSM, Class 2, WA	8	7	7	7	8	7	6	6	6	6	4	4	4	4	4	4	4	3	3	3	68	108
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	30	30	30	30	30	361	649
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	108	229	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	361	380
	FOT MidColumbia Q3 - 2	375	375	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	372	374
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	187	160	134	113	95	96	142	84	120	1,474	82	137	992	197	854	127	212		
	Annual Additions, Short Term Resources	650	709	845	983	1,104	1,210	1,328	1,425	1,197	1,338	1,432	1,434	1,273	1,395	1,471	1,472	1,472	1,471	1,471	1,471		
	Total Annual Additions	790	1,485	966	1,170	1,264	1,344	1,441	1,520	1,293	1,480	1,516	1,554	2,747	1,477	1,608	2,464	1,669	2,325	1,598	1,683		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-03		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	1,322	-	-	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	3.6	7.3
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	4	4	-	-	-	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	7	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	4	-	-	18	-	-	-	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	2	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	1	8	111	-	20	-	-	-	-	16	-	157
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	61	54	51	49	47	45	42	42	40	30	33	30	28	27	25	23	22	21	20	494	752
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	55	125
	DSM, Class 2 Total	69	67	61	59	57	55	54	52	52	51	39	42	39	38	37	35	33	32	31	30	579	935
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	40	159	256	28	170	263	263	299	190	300	40	40	178	228	300	65	138
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	15
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	24	46	-	2	-	-	-	-	31	-	103
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	22	22	22	18	19	22	22	26	282	500
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	26	29	28	27	27	27	28	22	23	26	26	30	359	623
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	229	297	297	297	297	297	297	297	297	297	297	161	262	297	297	297	182	231
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	361	380
	FOT MidColumbia Q3 - 2	375	375	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	372	374
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	(387)	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	148	137	112	95	95	142	91	550	457	743	104	1,396	72	678	73	124		
	Annual Additions, Short Term Resources	650	709	845	984	1,104	1,212	1,331	1,428	1,200	1,342	1,435	1,435	1,471	1,362	1,472	1,076	1,177	1,350	1,400	1,472		
	Total Annual Additions	790	1,485	966	1,174	1,252	1,349	1,443	1,523	1,295	1,484	1,526	1,985	1,928	2,105	1,576	2,472	1,249	2,028	1,473	1,596		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-04	Capacity (MW)																				Resource Totals 1/	
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East																						
Existing Plant Retirements/Conversions																						
Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	(450)
Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
Expansion Resources																						
CCCT F 2x1	-	-	-	-	-	-	-	-	-	-	634	-	-	-	-	-	-	-	-	-	-	634
CCCT FD 2x1	-	-	-	-	661	-	-	1,322	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
CCCT GH 2x1	-	-	-	-	-	-	-	-	-	736	-	-	-	-	736	-	-	-	-	-	736	1,472
CCCT J 1x1	-	-	-	-	-	-	423	-	423	423	-	-	-	-	-	-	-	-	-	411	1,269	1,680
Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	3	2	2	3	3	3	3	3	3	3	2	27	53
DSM, Class 2, UT	63	55	50	48	45	43	41	39	39	39	30	33	30	28	27	25	23	22	21	20	463	721
DSM, Class 2, WY	3	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	54	123
DSM, Class 2 Total	68	62	58	56	54	52	49	48	49	49	38	41	38	38	37	35	33	32	31	29	545	897
Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
FOT Mona Q3	-	-	112	185	74	186	209	125	83	-	-	-	109	232	33	40	40	250	300	88	97	103
West																						
Existing Plant Retirements/Conversions																						
JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
Expansion Resources																						
Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
DSM, Class 2, OR	35	40	33	32	29	26	22	19	17	17	17	19	19	19	20	22	22	22	22	19	270	471
DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	64	101
DSM, Class 2 Total	43	48	41	40	37	33	29	25	24	24	22	24	24	24	25	26	26	26	26	22	344	589
OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
FOT COB Q3	38	65	342	297	297	297	297	297	297	233	179	212	297	297	99	153	211	297	297	297	246	240
FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	-	-	41	100	100	100	100	87
FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
FOT MidColumbia Q3 - 2	114	151	270	375	375	375	375	375	375	375	375	375	375	375	361	375	375	375	375	375	316	345
Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	-	(279)	(1,084)	(597)	(788)	(442)	-	-	-	-	-	-	(338)	(74)	-		
Annual Additions, Long Term Resources	138	770	116	113	770	99	516	1,412	512	1,249	711	82	79	78	814	78	76	74	74	479		
Annual Additions, Short Term Resources	652	716	1,224	1,357	1,246	1,358	1,381	1,297	1,255	1,108	1,054	1,087	1,281	1,404	893	968	1,067	1,422	1,472	1,260		
Total Annual Additions	790	1,486	1,340	1,470	2,016	1,457	1,897	2,709	1,767	2,357	1,765	1,169	1,360	1,482	1,707	1,046	1,143	1,496	1,546	1,739		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-05	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	-	-	-	-	(416)	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	661	661	-	-	-	-	-	-	-	-	-	-	-	1,322	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	-	-	-	-	736	736
	CCCT J 1x1	-	-	-	-	-	423	423	423	-	423	-	-	-	-	-	411	-	411	-	-	1,692	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	15	-	-	-	-	665
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	15	-	-	-	202	873
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.5	7.9	7.9	7.9	7.9	-	39.1
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	3.7	3.6	27.3
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37	15	37	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	3	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1	68	15	59	3	1	11	-	158
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	56	54	51	49	47	45	43	42	40	30	33	30	28	27	26	25	23	22	21	490	756
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	8	8	55	128
	DSM, Class 2 Total	69	63	61	59	57	55	54	52	52	51	39	43	39	38	38	36	35	33	33	32	575	942
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	263	164	248	181	232	-	-	-	187	299	282	282	300	300	300	299	109	167

	EG-5 Case C-05, cont.	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	-	-	-	-	423	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Fly Wheel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	10
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	5
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2	2.3	2.3	2.3	2.3	-	9.4
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	-	2.7
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	6	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	2	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	3	69	-	6	-	33	5	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	19
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	20	23	23	22	22	26	26	26	26	26	26	26	281	527
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	5	5	4	4	3	3	3	67	108
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	27	30	28	27	27	32	32	31	30	30	30	30	358	655
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	143	124	297	297	297	297	297	181	272	297	297	297	297	297	297	297	297	297	203	249
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	149	207	353	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	307	341
	Existing Plant Retirements/Conversions	-	-	(164)	8	(378)	(158)	(353)	(853)	(1,355)	(568)	8	-	-	-	-	(328)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	772	120	190	148	560	534	1,180	1,180	1,302	90	519	303	93	226	520	175	507	127	214		
	Annual Additions, Short Term Resources	651	713	850	977	1,435	1,336	1,420	1,353	1,404	1,056	1,147	1,172	1,359	1,471	1,454	1,454	1,472	1,472	1,472	1,471		
	Total Annual Additions	791	1,485	970	1,167	1,583	1,896	1,954	2,533	2,584	2,358	1,237	1,691	1,662	1,564	1,680	1,974	1,647	1,979	1,599	1,685		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-06		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	2	3	3	3	3	3	3	3	32	59
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	508	767
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	6	7	7	7	7	7	7	7	56	126
	DSM, Class 2 Total	73	67	61	60	59	61	58	53	52	51	40	43	38	38	37	35	33	32	31	30	596	952
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	28	142	237	6	148	241	263	40	40	147	201	300	59	109	232	56	110
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	11
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	31	28	24	23	23	23	23	22	19	19	19	22	22	19	22	22	295	504
	DSM, Class 2, WA	8	8	8	8	8	7	7	6	7	7	5	5	5	5	5	3	3	3	3	3	71	110
	DSM, Class 2 Total	45	49	42	41	40	35	32	31	30	30	29	28	25	24	24	26	26	23	26	26	376	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	127	126	243	258	297	297	297	297	297	297	297	297	145	269	297	297	297	297	297	297	254	266
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	220	300	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	119	117	111	105	98	99	98	85	100	740	79	78	923	76	1,155	73	73		
	Annual Additions, Short Term Resources	646	705	841	978	1,097	1,200	1,314	1,409	1,178	1,320	1,413	1,435	1,060	1,184	1,319	1,373	1,472	1,231	1,281	1,404		
	Total Annual Additions	791	1,482	962	1,097	1,214	1,311	1,419	1,507	1,277	1,418	1,498	1,535	1,800	1,263	1,397	2,296	1,548	2,386	1,354	1,477		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-07		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	-	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	423	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	3	-	-	653
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	3	-	202	861
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	4	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	40	-	-	51
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	3
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	27	44	-	-	87
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	61	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	499	759
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	7	7	56	127
	DSM, Class 2 Total	69	67	61	59	59	57	57	52	52	51	39	42	39	38	37	35	33	32	32	30	586	945
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	36	151	248	19	162	257	-	134	255	298	40	40	297	300	277	62	126
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	22	22	22	23	22	23	26	26	22	285	516
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	112
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	28	28	28	29	27	28	30	30	26	365	646
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	130	247	268	297	297	297	297	297	297	297	238	297	297	297	156	254	297	297	297	256	264
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	215	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	166	259	307
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	777	121	191	151	140	117	96	96	141	90	942	302	83	172	1,400	77	528	125	493		
	Annual Additions, Short Term Resources	650	709	845	983	1,102	1,208	1,323	1,420	1,191	1,334	1,429	1,113	1,306	1,427	1,470	1,071	1,169	1,469	1,472	1,240		
	Total Annual Additions	791	1,486	966	1,174	1,253	1,348	1,440	1,516	1,287	1,475	1,519	2,055	1,608	1,510	1,642	2,471	1,246	1,997	1,597	1,733		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-08	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	1,322	661	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	736	-	-	736	-	-	-	-	-	-	-	736	-	-	-	-	1,472	2,208
	CCCT J 1x1	-	-	-	-	-	-	-	-	423	-	423	-	423	-	-	-	-	-	-	-	423	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	509	-	509
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	509	-	509
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3	3	3	3	3	3	28	56
	DSM, Class 2, UT	63	56	54	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	484	742
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	51	39	42	39	38	37	35	33	32	31	30	567	922
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	175	-	93	-	70	-	124	108	140	40	111	240	40	40	129	179	300	57	95
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	17
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	19	19	19	19	19	22	22	22	22	19	275	478
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	24	26	25	24	24	24	24	26	26	26	26	22	352	599
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	291	297	184	297	281	297	297	297	245	297	297	33	123	297	297	297	239	243
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	-	9	100	100	100	100	90
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(1,279)	(279)	(816)	(548)	-	(268)	-	-	-	-	-	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	117	849	1,425	757	827	514	94	503	83	502	78	77	814	76	74	74	578		
	Annual Additions, Short Term Resources	651	714	1,219	1,347	1,166	1,265	1,059	1,242	1,156	1,296	1,280	1,312	1,160	1,283	1,412	848	947	1,301	1,351	1,472		
	Total Annual Additions	791	1,485	1,339	1,464	2,015	2,690	1,816	2,069	1,670	1,390	1,783	1,395	1,662	1,361	1,489	1,662	1,023	1,375	1,425	2,050		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-09	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	Johnston3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	Johnston4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	-	-	-	-	-	-	(328)	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	661	1,322	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,983	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	736	-	-	-	-	736	-	-	-	-	736	-	-	736	2,208
	CCCT J 1x1	-	-	-	-	-	-	-	423	423	-	423	-	-	-	-	-	-	-	-	-	846	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	33	14	-	-	49	-	-	-	-	-	-	-	-	-	-	204	204
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	42	-	439	-	-	-	-	-	-	-	509	42	990
	Total Wind	-	-	-	73	35	33	14	-	-	91	-	439	-	-	-	-	-	-	-	509	246	1,194
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	2	3	3	3	3	3	3	3	28	55
	DSM, Class 2, UT	63	56	54	51	49	47	44	40	40	40	30	33	30	28	27	25	23	22	21	20	484	742
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	6	7	7	7	7	7	8	55	124
	DSM, Class 2 Total	69	62	61	59	57	55	53	49	50	51	39	42	38	37	37	35	33	32	31	30	567	921
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	-	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	109	175	60	64	249	86	-	233	217	246	40	40	54	129	228	125	175	293	98	126
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,441	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	18
	DSM, Class 2, OR	36	40	33	32	29	26	22	19	17	19	19	19	19	19	19	22	22	22	22	23	275	482
	DSM, Class 2, WA	7	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	103
	DSM, Class 2 Total	45	49	41	41	38	33	29	26	24	26	25	24	24	24	24	26	26	26	26	27	352	603
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	37	64	342	297	297	297	297	297	297	297	297	297	59	183	297	297	297	297	297	297	252	257
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	114	150	268	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	316	345
	Existing Plant Retirements/Conversions	-	-	(582)	8	(378)	(1,173)	(74)	(816)	(548)	(106)	(268)	-	-	-	-	-	-	(543)	(74)	-		
	Annual Additions, Long Term Resources	140	771	120	190	809	1,458	110	1,250	514	185	503	522	814	78	77	78	76	810	74	583		
	Annual Additions, Short Term Resources	651	714	1,219	1,347	1,232	1,236	1,421	1,258	1,172	1,405	1,389	1,418	974	1,098	1,226	1,301	1,400	1,297	1,347	1,465		
	Total Annual Additions	791	1,485	1,339	1,537	2,041	2,694	1,531	2,508	1,686	1,590	1,892	1,940	1,788	1,176	1,303	1,379	1,476	2,107	1,421	2,048		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-10	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	-	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	7.9	-	15.8
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	2.7	0.8	2.7	2.7	3.6	14.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	15	-	-	40	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	11	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	38	-	-	57	-	13	51	-	158
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	24	22	22	21	495	757
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	8	8	56	128
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	34	32	32	32	581	943
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	256	27	169	263	67	262	297	272	286	298	278	300	298	65	164
West	**Expansion Resources**																						
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	15
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	2.3	-	4.6
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	0.4	-	0.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	22	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	48	-	-	24	-	-	44	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	26	26	26	26	26	284	523
	DSM, Class 2, WA	8	7	7	7	8	6	6	6	6	6	4	4	4	4	4	4	4	3	3	3	68	107
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	30	30	30	30	30	361	649
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	361	380
	FOT MidColumbia Q3 - 2	375	375	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	372	374
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	100	95	96	98	84	747	83	168	263	924	164	925	104	202		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,428	1,199	1,341	1,435	1,239	1,434	1,469	1,444	1,458	1,470	1,450	1,472	1,470		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,431	1,523	1,295	1,439	1,519	1,986	1,517	1,637	1,707	2,382	1,634	2,375	1,576	1,672		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-11		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	7.9	7.9	-	16.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.8	0.8	0.8	2.7	2.7	2.7	3.6	15.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	4	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	3	-	7	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1	127	11	-	7	1	11	-	158
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	31	60
	DSM, Class 2, UT	65	61	54	51	49	48	45	43	42	40	30	33	30	28	27	26	24	23	22	21	497	762
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	7	7	8	7	7	7	8	8	56	128
	DSM, Class 2 Total	71	67	61	59	57	57	55	52	52	51	39	43	39	38	38	36	34	33	33	32	584	950
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	36	154	251	23	164	258	58	251	298	299	300	217	300	300	300	63	160
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	203	-	-	-	-	203
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	11	-	17
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	11	-	17
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	15
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4	2.3	2.3	-	6.1
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.4	0.4	0.4	-	1.5
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	2	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	1	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	70	2	1	-	6	33	5	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	26	26	26	26	26	26	26	284	530
	DSM, Class 2, WA	8	7	7	7	8	7	6	6	6	6	4	4	4	5	5	4	4	4	3	3	68	109
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	32	32	31	30	30	30	30	362	659
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	106	227	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	173	232	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	361	380
	FOT MidColumbia Q3 - 2	375	375	343	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	372	373
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	142	776	121	190	148	139	113	96	96	144	90	1,180	301	158	215	937	285	759	133	225		
	Annual Additions, Short Term Resources	648	707	843	981	1,102	1,208	1,326	1,423	1,195	1,336	1,430	1,230	1,423	1,470	1,471	1,472	1,389	1,472	1,472	1,472		
	Total Annual Additions	790	1,483	964	1,171	1,250	1,347	1,439	1,519	1,291	1,480	1,520	2,410	1,724	1,628	1,686	2,409	1,674	2,231	1,605	1,697		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-12

	EG-5 Case C-12	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	411	-	-	423	-	423	423	-	-	-	1,680
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93	-	-	93
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93	-	-	93
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	-	88
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	12	-	25
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	13	100	-	114
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	56	54	51	50	48	48	43	42	40	30	33	30	28	27	25	23	22	21	20	494	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	8	56	126
	DSM, Class 2 Total	69	63	61	59	59	57	57	52	52	51	39	42	39	38	37	35	33	32	32	31	581	938
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	42	157	254	25	169	263	-	158	280	66	240	40	299	300	294	65	129
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8	0	-	16
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	25	-	46
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	33	25	-	75
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	24	21	20	20	23	19	22	22	22	22	23	26	26	26	285	515
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	7	5	5	5	5	5	4	4	3	3	3	71	111
	DSM, Class 2 Total	45	49	42	41	38	35	32	28	27	27	28	25	28	28	28	27	28	30	30	30	365	645
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	134	251	267	297	297	297	297	297	297	297	260	297	297	297	297	248	297	297	297	257	272
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	221	311	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	121	118	116	106	103	95	96	95	84	495	83	82	504	739	500	520	217	202		
	Annual Additions, Short Term Resources	650	713	849	988	1,108	1,214	1,329	1,426	1,197	1,341	1,435	1,135	1,330	1,452	1,238	1,412	1,163	1,471	1,472	1,466		
	Total Annual Additions	791	1,485	970	1,106	1,224	1,320	1,432	1,521	1,293	1,436	1,519	1,630	1,413	1,534	1,742	2,151	1,663	1,991	1,689	1,668		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-13	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423	-	-	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	36	33	12	-	-	45	4	-	-	-	-	-	-	-	-	-	199	203
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	13
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	379	234	-	-	-	-	-	93	-	-	706
	Total Wind	-	-	-	73	36	33	12	-	-	45	4	379	234	-	-	-	-	13	93	-	199	922
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	4	4	3	3	3	3	3	3	3	3	3	3	30	58
	DSM, Class 2, UT	63	58	54	51	50	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	494	752
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	56	124
	DSM, Class 2 Total	69	65	61	59	59	57	54	52	52	51	39	42	39	38	37	35	33	32	31	30	580	935
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	40	157	254	26	169	263	-	146	269	57	231	300	59	110	233	65	116
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	8
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	22
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	26	24	21	20	20	23	19	19	19	20	22	22	19	19	22	283	487
	DSM, Class 2, WA	8	7	8	8	8	7	7	6	6	6	5	5	5	5	5	3	4	3	3	3	70	110
	DSM, Class 2 Total	45	49	42	41	38	34	32	28	27	27	28	25	25	24	26	26	26	23	23	26	363	614
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	131	132	249	270	297	297	297	297	297	297	297	247	297	297	297	297	297	297	297	297	256	274
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	19	79	98	215	308	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	259	317
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	774	121	191	152	138	112	95	96	140	88	885	314	79	502	739	106	1,168	163	72		
	Annual Additions, Short Term Resources	650	711	847	985	1,105	1,212	1,329	1,426	1,198	1,341	1,435	1,122	1,318	1,441	1,229	1,403	1,472	1,231	1,282	1,405		
	Total Annual Additions	791	1,485	968	1,176	1,257	1,350	1,441	1,521	1,294	1,481	1,523	2,007	1,632	1,520	1,731	2,142	1,578	2,399	1,445	1,477		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-14	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	-	-	-	-	-	(416)	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	(459)
	Huntington2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	(205)	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	661	-	661	-	-	-	1,983
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	-	-	-	-	-	736
	CCCT J 1x1	-	-	-	-	-	-	423	1,680	-	423	-	411	-	-	-	-	-	-	-	-	2,526	2,937
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	850	-	-	432	218	-	-	-	-	-	-	-	850	1,500
	Total Wind	-	-	-	73	35	34	13	1	850	46	6	432	218	-	-	-	-	-	-	-	1,052	1,708
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	6	6	7	3	3	3	3	3	1	1	1	2	1	1	1	1	1	1	47	60
	DSM, Class 2, UT	84	76	75	73	73	50	47	41	41	39	14	13	11	11	10	13	11	10	8	7	599	707
	DSM, Class 2, WY	24	24	24	25	25	3	3	3	3	2	2	2	1	2	2	2	2	1	1	1	137	154
	DSM, Class 2 Total	114	106	105	104	105	56	54	47	47	45	17	17	13	14	13	17	14	12	11	10	783	922
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.2	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	52	157	-	131	-	-	50	162	40	288	40	56	173	40	44	186	34	71
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	JBridger3 (Early Retirement/Conversion)	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JBridger4 (Early Retirement/Conversion)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip4 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	357	362	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	1,079	1,441
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	1	1	0	0	15	20
	DSM, Class 2, OR	37	41	34	33	31	28	24	23	21	21	21	20	20	20	20	20	20	20	21	21	293	498
	DSM, Class 2, WA	13	13	13	14	14	6	6	6	6	6	2	2	2	2	2	2	2	2	2	2	97	114
	DSM, Class 2 Total	52	55	49	49	47	35	31	30	28	28	23	22	22	23	23	23	23	23	23	23	405	632
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	54	23	77	297	297	291	297	199	-	297	297	-	297	122	297	297	232	297	297	154	198
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	107	75	200	236	375	375	309	375	375	375	375	375	369	375	375	375	375	375	375	375	280	327
	Existing Plant Retirements/Conversions	-	-	(164)	8	(378)	-	-	(1,674)	-	(3)	(261)	(450)	-	(459)	-	(760)	-	(338)	(74)	-		
	Annual Additions, Long Term Resources	193	822	173	243	206	141	535	1,772	941	558	63	898	1,006	54	713	717	53	712	50	49		
	Annual Additions, Short Term Resources	607	629	723	813	1,224	1,329	1,100	1,303	1,074	875	1,222	1,334	909	1,460	1,037	1,228	1,345	1,147	1,216	1,358		
	Total Annual Additions	800	1,451	896	1,056	1,430	1,470	1,635	3,075	2,015	1,433	1,285	2,232	1,915	1,514	1,750	1,945	1,398	1,859	1,266	1,407		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-15	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	362	-	362	-	-	-	905
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	SCCT Frame WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181
	SCCT Frame WYNE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	515	-	-	-	-	-	515
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.8	2.7	2.7	0.4	0.4	3.6	12.5
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	74	-	-	4	-	-	-	-	-	77
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	19	3	-	-	-	-	-	-	22
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	4
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	74	45	3	4	-	4	-	-	-	129
	DSM, Class 2, ID	6	6	6	6	6	2	2	2	2	3	1	1	1	2	1	1	1	1	1	1	39	52
	DSM, Class 2, UT	81	74	68	65	63	39	37	37	37	37	12	11	9	10	9	12	10	9	7	6	537	634
	DSM, Class 2, WY	23	23	23	23	24	2	2	2	2	2	2	2	1	2	2	2	2	1	1	1	128	144
	DSM, Class 2 Total	111	103	97	94	92	43	41	41	41	42	16	14	12	13	12	15	13	12	10	9	704	830
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	6	114	-	55	171	230	198	300	297	298	258	300	215	204	18	132
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	384	-	-	-	565
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	-	-	0.3
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	21
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	1	-	-	-	24
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	0	0	0	1	1	1	0	0	0	0	13	16
	DSM, Class 2, OR	36	41	33	32	29	26	22	19	17	17	18	17	18	17	19	19	19	19	17	17	274	453
	DSM, Class 2, WA	12	12	12	12	12	5	5	5	5	5	2	1	1	1	1	2	1	1	1	1	86	98
	DSM, Class 2 Total	51	55	47	46	43	32	28	24	23	23	20	19	19	19	20	21	21	21	18	18	373	568
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	-	56	174	297	297	196	297	297	297	297	297	297	297	297	297	297	297	132	214
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	135	160	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	350	375
	FOT MidColumbia Q3 - 2	375	375	237	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	358	367
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	188	818	163	231	189	123	97	81	80	128	58	482	542	94	234	934	234	803	225	224		
	Annual Additions, Short Term Resources	610	635	737	845	931	1,049	1,178	1,286	1,071	1,227	1,343	1,402	1,370	1,472	1,469	1,470	1,430	1,472	1,387	1,376		
	Total Annual Additions	798	1,453	900	1,076	1,120	1,172	1,275	1,367	1,151	1,355	1,401	1,884	1,912	1,566	1,703	2,404	1,664	2,275	1,612	1,600		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-16	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,322	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	115	-	-	-	-	-	-	-	115
	Wind, GO, 29	-	-	-	-	63	-	-	-	-	63	-	-	-	-	-	-	-	-	-	-	126	126
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	-	446	-	-	-	-	-	-	-	-	446
	Total Wind	-	-	-	-	63	-	-	-	-	63	-	-	446	-	-	-	-	-	-	-	126	572
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	13
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	0	-	-	106	-	-	-	-	-	-	106
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	2	2	2	2	2	30	54
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	753
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	7	56	124
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	33	31	30	30	29	581	931
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	17	136	233	4	145	237	263	290	297	300	40	40	116	170	296	54	129
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	25	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	25	30
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	8	8	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	21
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	3	8	8	8	23	-	-	-	-	-	-	50
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	18	18	18	18	18	284	487
	DSM, Class 2, WA	8	7	7	7	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	105
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	30	28	27	27	28	28	22	22	22	22	22	361	610
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	87	207	297	297	297	297	297	297	297	297	297	297	163	266	297	297	297	178	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	175	234	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	361	380
	FOT MidColumbia Q3 - 2	375	375	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	372	374
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	142	176	104	100	95	96	161	87	95	717	210	211	1,394	70	730	68	68		
	Annual Additions, Short Term Resources	650	709	845	962	1,082	1,189	1,308	1,405	1,176	1,317	1,409	1,435	1,462	1,469	1,472	1,078	1,181	1,288	1,342	1,468		
	Total Annual Additions	790	1,485	966	1,104	1,258	1,293	1,408	1,500	1,272	1,478	1,496	1,530	2,179	1,679	1,683	2,472	1,251	2,018	1,410	1,536		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-17		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	423	-	423	-	-	-	1,269
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	686	-	-	-	164	-	-	-	1,500
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	686	-	-	-	164	-	-	202	1,708
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	44	-	-	3	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	2	-	25
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	63	53	-	22	10	-	149
	DSM, Class 2, ID	3	3	3	4	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	34	62
	DSM, Class 2, UT	68	61	57	55	53	51	48	44	44	42	31	34	30	29	28	27	25	23	22	21	523	793
	DSM, Class 2, WY	4	4	5	5	6	6	7	7	7	8	7	7	7	7	8	7	7	7	8	8	59	132
	DSM, Class 2 Total	74	68	65	64	63	61	59	55	55	53	41	43	40	40	39	37	35	33	32	32	616	987
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	0.8	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	52	-	-	52	100	285	53	169	53	53	129	159	264	5	68
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	420	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	3
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	3
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	11	21
	DSM, Class 2, OR	37	41	34	34	33	31	27	24	24	24	24	26	26	26	26	26	26	26	26	26	308	563
	DSM, Class 2, WA	8	8	8	8	8	7	7	7	7	7	5	5	5	5	5	4	4	3	3	3	75	119
	DSM, Class 2 Total	46	50	43	43	42	39	35	32	32	32	30	32	31	32	32	30	30	30	30	30	395	702
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	163	125	239	291	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	260	279
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	383	400	400	400	330	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	391	396
	FOT MidColumbia Q3 - 2	-	79	97	178	-	31	142	183	3	142	183	163	168	164	177	54	95	186	181	182	86	120
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	146	778	126	198	579	148	122	103	103	148	93	524	306	1,198	87	1,231	135	848	101	91		
	Annual Additions, Short Term Resources	646	704	836	969	727	828	939	1,032	800	939	1,032	1,060	1,250	1,014	1,143	904	945	1,112	1,137	1,243		
	Total Annual Additions	792	1,482	962	1,167	1,306	976	1,061	1,135	903	1,087	1,125	1,584	1,556	2,212	1,230	2,135	1,080	1,960	1,238	1,334		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-5 Case C-18

		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Hunter1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(416)	-	-	-	-	-	-	-	(416)
	Hunter2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	(269)
	Hunter3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(479)	-	-	-	-	-	-	-	-	(479)
	Huntington1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	(459)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	(158)	-	-	-	-	-	-	-	-	-	-	-	-	(158)	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Wyodak1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	WY IGCC CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	456	-	456
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	1,245	-	846	-	-	-	2,514
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	2,236	-	-	-	-	-	-	-	-	2,236
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	Wind, GO, 29	-	-	-	-	-	-	-	-	-	263	122	50	11	154	-	-	-	-	-	-	263	600
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	-	200
	Wind, Wyoming, 40	-	-	-	-	-	-	-	650	850	-	-	-	-	-	-	-	-	-	-	-	1,500	1,500
	Total Wind	-	-	-	-	-	-	-	650	850	263	322	50	11	154	-	-	-	-	-	-	1,763	2,300
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	6	6	8	8	7	3	3	3	3	3	1	1	1	2	2	2	1	1	1	1	51	65
	DSM, Class 2, UT	88	81	83	81	80	52	49	43	42	40	14	13	11	12	11	14	11	10	9	8	640	751
	DSM, Class 2, WY	25	25	25	26	26	3	3	3	3	3	3	2	2	2	2	2	2	2	1	1	141	159
	DSM, Class 2 Total	120	112	115	115	114	58	55	49	48	46	18	17	13	15	14	17	15	13	12	10	831	974
	Utility Solar - PV	-	-	-	-	-	-	-	-	-	-	-	-	-	450	-	-	-	-	-	-	-	450
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.4	13.4	13.4	131	263
	Micro Solar - Water Heating	-	-	-	0.4	0.3	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	-	-	122	-	38	-	-	-	53	276	53	135	53	65	53	16	42
West	**Existing Plant Retirements/Conversions**																						
	JBridger1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	(354)
	JBridger2 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	(363)	-	-	-	-	-	-	-	-	-	-	(363)	(363)
	Colstrip3 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	(74)
	Coal Ret_Bridger -Gas RePower	-	-	-	-	-	-	-	-	-	360	362	-	-	-	-	-	-	-	-	-	360	722
	Expansion Resources																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	Wind, HM, 29	-	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	600
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	600
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	2	2	2	2	2	1	1	1	1	1	1	0	0	1	1	1	1	1	1	0	16	22
	DSM, Class 2, OR	41	44	40	38	34	31	28	25	23	23	22	21	21	21	21	21	21	21	21	21	327	535
	DSM, Class 2, WA	14	14	14	14	14	7	7	6	6	6	2	2	2	3	3	3	2	2	2	2	104	127
	DSM, Class 2 Total	57	60	56	55	51	38	36	33	30	30	25	24	24	24	24	24	24	23	23	23	447	684
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	99	33	-	78	108	196	297	297	187	297	84	248	-	-	297	263	297	241	297	49	159	168
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	-	81	196	206	240	255	265	375	375	375	375	375	4	340	375	375	375	375	375	375	237	286
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	(158)	-	(3)	8	(269)	(1,134)	(490)	(459)	(760)	-	(543)	(74)	-		
	Annual Additions, Long Term Resources	203	832	189	187	183	111	106	746	945	356	804	842	2,301	660	54	1,303	55	899	51	506		
	Annual Additions, Short Term Resources	599	614	696	784	848	951	1,062	1,294	1,062	1,210	959	1,123	504	893	1,448	1,191	1,307	1,169	1,237	977		
	Total Annual Additions	802	1,446	885	971	1,031	1,062	1,168	2,040	2,007	1,566	1,763	1,965	2,805	1,553	1,502	2,494	1,362	2,068	1,288	1,483		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-5 Case C-19	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	-	-	-	-	-	661
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	-	-	-	-	368
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	736	-	-	-	1,472
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	35	34	13	1	-	46	6	-	-	-	-	-	-	-	-	-	202	208
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	35	34	13	1	-	46	6	432	218	-	-	-	-	-	-	-	202	858
	CHP - Biomass	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	7	77	-	-	-	-	-	-	85
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	22
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	1	-	-	4	0	-	7	108	-	-	-	-	-	1	121
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	3	3	3	2	2	2	2	2	31	55
	DSM, Class 2, UT	67	61	54	51	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	507	766
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	7	56	125
	DSM, Class 2 Total	73	67	61	59	59	61	58	52	52	51	39	42	39	38	37	34	32	31	30	29	595	946
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	1.1	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	29	143	237	9	150	237	245	208	277	300	106	206	244	300	65	57	138
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	3	24	-	45	1	-	-	-	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	26	24	23	20	23	23	22	22	22	22	18	19	20	22	18	289	498
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	69	106
	DSM, Class 2 Total	45	49	41	41	38	34	32	30	27	30	28	27	27	28	28	22	23	24	26	22	367	622
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	103	223	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	171	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	377	389
	FOT MidColumbia Q3 - 2	375	205	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	355	365
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	191	150	144	117	100	96	144	97	542	961	134	191	1,177	71	807	72	491		
	Annual Additions, Short Term Resources	646	705	840	978	1,098	1,201	1,315	1,409	1,181	1,322	1,409	1,417	1,380	1,449	1,472	1,278	1,378	1,416	1,472	1,237		
	Total Annual Additions	791	1,482	961	1,169	1,248	1,345	1,432	1,509	1,277	1,466	1,506	1,959	2,341	1,583	1,663	2,455	1,449	2,223	1,544	1,728		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.12 – Sensitivity Cases under Energy Gateway Scenario 2, excluding S-04 and S-X that are included in Confidential Volume III

	EG-2 Case S-01	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	181	-	-	-	-	362
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	0.4	2.7	2.7	2.7	3.6	14.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	1	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	74	-	-	-	-	-	-	-	15	-	-	-	3	74	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	3	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	10	9	-	-	-	-	-	-	-	3	-	-	-	2	19	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	DSM, Class 1 Total	-	-	-	-	-	-	11	83	-	-	-	-	-	-	-	45	-	3	4	11	94	157
	DSM, Class 2, ID	3	3	3	4	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	61
	DSM, Class 2, UT	67	61	54	52	53	51	48	43	42	40	30	33	30	28	27	26	23	23	22	21	512	774
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	8	8	56	128
	DSM, Class 2 Total	73	67	62	61	63	61	58	52	52	51	39	43	39	38	37	36	33	33	32	32	601	964
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.1	1.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	140	228	256	255	21	158	243	263	291	226	188	300	222	300	300	300	106	185
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	-	-	-	-	-	197
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.9	0.9	-	1.8
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.4	0.3	-	0.9
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	0	15	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	44	-	-	-	-	-	-	-	-	-	-	-	-	3	44	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	15	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	70	-	-	-	-	-	-	-	-	3	-	6	19	18	70	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	37	41	33	32	29	28	27	21	20	23	23	22	22	22	24	26	23	26	26	26	291	530
	DSM, Class 2, WA	8	7	8	8	8	7	6	6	6	6	4	4	4	4	5	4	4	3	3	3	69	109
	DSM, Class 2 Total	46	49	42	41	38	36	34	28	27	30	28	27	27	28	30	30	28	30	30	30	370	658
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	-	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	178	238
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	109	141	400	386	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	344	372
	FOT MidColumbia Q3 - 2	375	375	237	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	361	368
	Existing Plant Retirements/Conversions	-	-	(164)	-	(387)	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	122	192	153	144	203	178	96	143	89	455	545	279	265	793	259	752	106	224		
	Annual Additions, Short Term Resources	584	616	737	861	1,312	1,400	1,428	1,427	1,193	1,330	1,415	1,435	1,463	1,398	1,360	1,472	1,394	1,472	1,472	1,472		
	Total Annual Additions	729	1,393	859	1,053	1,465	1,544	1,631	1,605	1,289	1,473	1,504	1,890	2,008	1,677	1,625	2,265	1,653	2,224	1,578	1,696		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case S-02		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	661	-	661	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	181	-	-	362
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	0.4	0.4	0.4	3.6	7.6
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	37	-	-	-	-	-	37	-	11	4	-	-	3	37	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	22
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	22
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0	-	-	0	0	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	38	-	-	-	-	-	37	-	13	58	-	-	3	38	149
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	32	60
	DSM, Class 2, UT	67	61	54	51	50	51	48	43	42	40	30	33	30	28	27	25	23	22	21	20	507	766
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	7	8	56	126
	DSM, Class 2 Total	73	67	61	59	59	61	58	52	52	51	39	42	39	38	37	35	33	32	31	30	595	952
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.4	1.2	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	37	143	263	214	257	46	203	162	217	187	289	84	254	298	256	159	298	116	168
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame OR	-	-	-	-	-	-	203	-	-	-	-	-	-	-	-	-	-	-	-	-	203	203
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	2
	DSM, Class 1, OR-Curtail	-	-	-	-	21	-	-	22	-	-	-	-	-	-	-	-	-	-	-	3	44	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	14
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1 Total	-	-	-	-	21	-	-	30	-	-	-	-	-	-	-	-	14	-	-	4	51	69
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	18
	DSM, Class 2, OR	37	41	33	32	29	26	24	23	20	19	20	19	22	22	22	22	22	19	22	22	285	498
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	4	4	4	3	3	3	3	3	69	105
	DSM, Class 2 Total	45	49	41	41	38	34	32	30	26	26	25	24	27	27	27	26	26	23	26	26	364	621
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	7	190	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	228	262
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	270	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	365	370
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	191	171	142	322	165	95	139	267	451	1,025	119	504	752	148	913	254	102		
	Annual Additions, Short Term Resources	770	882	1,065	1,209	1,315	1,435	1,386	1,429	1,218	1,375	1,334	1,389	1,359	1,461	1,256	1,426	1,470	1,428	1,331	1,470		
	Total Annual Additions	915	1,659	1,186	1,400	1,486	1,577	1,708	1,594	1,313	1,514	1,601	1,840	2,384	1,580	1,760	2,178	1,618	2,341	1,585	1,572		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case S-03	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	661	-	661	-	-	-	1,983
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	362	-	181	-	-	-	543
	SCCT Frame ID	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	-	-	-	-	181	181
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	-	-	-	-	172	-	344
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	37	-	-	-	-	-	-	48	-	-	-	-	-	-	37	85
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
	DSM, Class 1 Total	-	-	-	-	-	9	38	-	-	-	-	-	-	48	-	-	-	-	-	-	47	95
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	3	4	3	3	3	3	2	2	2	2	3	2	32	56
	DSM, Class 2, UT	67	61	54	52	50	51	48	40	40	40	30	33	30	28	26	25	23	22	21	20	504	761
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	6	6	7	7	7	7	7	7	7	56	123
	DSM, Class 2 Total	73	67	61	61	59	61	58	49	50	51	39	42	39	38	35	33	32	31	31	29	591	940
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	10	154	261	207	249	200	-	127	227	261	231	300	292	159	270	216	271	251	121	184
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	197	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	197
	Utility Biomass	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	8	-	-	-	-	-	-	8	-	-	-	-	-	-	8	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, OR-Curtail	-	-	-	44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	44
	DSM, Class 1, OR-DLC-RES	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	13
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	4	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	44	13	-	19	-	-	-	-	-	-	9	-	-	-	-	-	-	76	85
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	9	16
	DSM, Class 2, OR	33	37	30	29	27	26	22	17	20	20	20	22	22	22	19	19	19	19	17	19	260	457
	DSM, Class 2, WA	7	7	7	7	7	6	6	5	5	5	4	4	4	4	4	3	3	3	3	3	63	94
	DSM, Class 2 Total	42	45	38	37	35	32	29	23	26	26	24	27	26	26	23	22	22	22	21	22	332	567
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	142	210	342	297	297	297	297	297	276	297	297	297	297	297	297	297	297	297	297	297	275	286
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	375	375	375	375	375	360	375	375	375	375	375	375	375	375	375	375	375	375	375	375	374	374
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	141	772	118	232	164	346	174	268	93	138	85	453	1,024	138	247	1,095	70	911	68	262		
	Annual Additions, Short Term Resources	1,017	1,085	1,227	1,326	1,433	1,364	1,421	1,372	1,151	1,299	1,399	1,433	1,403	1,472	1,464	1,331	1,442	1,388	1,443	1,423		
	Total Annual Additions	1,158	1,857	1,345	1,558	1,597	1,710	1,595	1,640	1,244	1,437	1,484	1,886	2,427	1,610	1,711	2,426	1,512	2,299	1,511	1,685		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG-2 Case S-05	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	1,322	-	-	-	-	-	1,983
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	423
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, Wyoming, 40	-	-	-	-	-	-	144	-	-	-	-	-	-	-	-	-	-	-	-	-	144	144
	Total Wind	-	-	-	-	-	-	144	-	-	-	-	-	-	-	-	-	-	-	-	-	144	144
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	4	74	-	-	88
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	3
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	7	74	-	-	106
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	2	2	30	57
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	21	20	495	754
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	7	7	7	7	7	7	55	124
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	33	32	30	29	581	934
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	0.2	1.4	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	158	255	26	169	263	260	226	297	275	40	40	292	272	251	65	143
West	**Expansion Resources**																						
	CCCT GH 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	420
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	8	-	-	-	15
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	44
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	13	-	51	-	-	-	8	-	-	-	72
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	17
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	22	23	22	19	22	19	19	22	22	18	18	282	487
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	68	104
	DSM, Class 2 Total	45	49	41	41	38	34	29	28	27	29	28	27	24	27	24	23	26	26	22	22	360	609
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	136	234	297	297	297	182	229
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	167	333	344
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	117	113	104	244	95	96	96	84	124	740	133	258	1,396	75	512	142	488		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,330	1,427	1,198	1,341	1,435	1,432	1,398	1,469	1,447	1,051	1,149	1,464	1,444	1,215		
	Total Annual Additions	790	1,485	966	1,101	1,218	1,317	1,574	1,522	1,294	1,437	1,519	1,556	2,138	1,602	1,705	2,447	1,224	1,976	1,586	1,703		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case S-06		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	846
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	91
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	69	51	45	109	-	-	-	-	-	-	-	-	-	-	-	-	-	274	274
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	31	-	52
	Wind, Wyoming, 40	-	-	-	-	-	-	400	-	-	-	-	250	-	-	-	-	-	-	-	-	400	650
	Total Wind	-	-	-	69	51	45	509	-	-	-	-	250	21	-	-	-	-	-	-	31	674	976
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	7.9	7.9	7.9	7.9	7.9	7.9	-	55.3
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	2.7	2.7	2.7	2.7	2.7	2.7	3.7	3.7	3.6	28.3
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	37	48	4	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	38	105	4	-	-	1	11	-	158
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	61
	DSM, Class 2, UT	67	61	54	52	50	51	48	43	42	40	30	33	30	29	28	27	25	23	23	22	508	778
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	8	7	7	7	7	8	7	7	8	8	8	57	131
	DSM, Class 2 Total	73	67	61	60	59	61	58	53	52	52	40	43	40	39	39	37	35	34	33	33	597	970
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	26	134	229	-	140	232	261	292	300	300	300	300	285	300	300	53	170
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	ICE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	117	-	-	-	117
	IC Aero WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	99
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	5	-	25
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	2.3	2.3	2.3	2.3	2.3	2.3	-	16.2
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-	3.3
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6	-	-	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	-	2	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	60	12	33	6	-	-	5	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	21
	DSM, Class 2, OR	37	41	33	32	29	28	27	23	23	23	25	26	26	26	26	26	26	26	26	26	296	552
	DSM, Class 2, WA	8	7	8	8	8	7	6	6	6	6	4	5	5	5	5	4	4	4	4	4	69	112
	DSM, Class 2 Total	46	49	42	41	38	35	34	30	30	30	30	32	32	32	32	31	30	30	30	31	375	685
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	102	221	297	297	297	296	297	297	297	297	297	297	297	297	297	297	297	181	239
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	204	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	188	166	155	617	98	99	98	87	342	293	199	218	981	191	871	115	245		
	Annual Additions, Short Term Resources	646	704	840	977	1,096	1,198	1,306	1,401	1,171	1,312	1,404	1,433	1,464	1,472	1,472	1,472	1,472	1,457	1,472	1,472		
	Total Annual Additions	791	1,481	961	1,165	1,262	1,353	1,923	1,499	1,270	1,410	1,491	1,775	1,757	1,671	1,690	2,453	1,663	2,328	1,587	1,717		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case S-07		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	91
	SCCT Frame UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, UT, 29	-	-	-	-	18	12	-	-	-	-	-	16	-	74	-	-	-	-	7	72	30	199
	Wind, Wyoming, 40	-	-	-	-	-	-	1	74	-	-	-	-	-	539	26	-	-	9	-	-	75	649
	Total Wind	-	-	-	-	18	12	1	74	-	-	-	16	-	613	26	-	-	9	7	72	105	848
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.9	7.9	7.9	7.9	-	31.6
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.8	2.7	2.7	2.7	2.7	2.7	2.7	3.6	21.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	7	77	4	-	-	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	4	-	-	-	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	1	-	8	126	11	-	-	1	11	-	158
	DSM, Class 2, ID	3	3	3	3	3	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	32	60
	DSM, Class 2, UT	67	61	54	51	50	48	48	43	42	40	30	33	30	28	28	26	25	23	22	21	504	770
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	7	7	7	7	8	7	7	7	8	8	56	129
	DSM, Class 2 Total	73	67	61	59	59	57	58	52	52	51	40	43	39	38	38	36	35	33	33	32	591	960
	Utility Solar - PV	-	-	-	100	-	-	-	-	-	-	-	-	-	100	-	-	-	100	-	-	100	300
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	23	137	232	-	143	236	263	299	300	300	299	298	298	299	300	54	171
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	IC Aero SO-CAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	91
	IC Aero WW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	99
	Geothermal, Greenfield	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	5
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	2.3	2.3	2.3	-	9.3
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	0.3	0.4	0.4	0.4	-	2.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	0	-	16
	DSM, Class 1, WA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	6	0	-	11
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	2	-	2	-	-	-	-	-	-	-	4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	2	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	5	-	67	-	-	7	-	33	5	-	116
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	20
	DSM, Class 2, OR	37	41	33	32	29	26	24	23	23	23	23	24	24	26	26	26	26	26	26	26	292	542
	DSM, Class 2, WA	8	7	7	8	8	7	6	6	6	6	4	4	4	5	5	4	4	4	3	3	69	110
	DSM, Class 2 Total	45	49	41	41	38	34	31	30	30	30	28	29	30	32	32	31	30	30	30	30	370	671
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	94	213	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	179	238
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	146	205	340	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	332	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	145	777	121	218	133	117	106	172	99	98	85	110	266	905	242	940	193	954	133	284		
	Annual Additions, Short Term Resources	646	705	840	969	1,088	1,195	1,309	1,404	1,172	1,315	1,408	1,435	1,471	1,472	1,472	1,471	1,470	1,470	1,471	1,472		
	Total Annual Additions	791	1,482	961	1,187	1,221	1,312	1,415	1,576	1,271	1,413	1,493	1,545	1,737	2,377	1,714	2,411	1,663	2,424	1,604	1,756		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	EG 2 - Case S09	Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	661	-	661	-	-	-	1,322
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	846	-	423	-	-	411	-	-	-	1,680
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	69	51	45	109	-	-	-	-	-	-	-	-	-	-	-	-	-	274	274
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	31	-	52
	Wind, Wyoming, 40	-	-	-	-	-	-	400	-	-	-	-	250	-	-	-	-	-	-	-	-	400	650
	Total Wind	-	-	-	69	51	45	509	-	-	-	-	250	21	-	-	-	-	-	-	31	674	976
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	3.6	7.2
	DSM, Class 2, ID	3	3	3	3	4	4	4	3	4	4	3	3	3	3	3	3	3	3	3	3	33	61
	DSM, Class 2, UT	68	61	57	55	53	53	50	44	44	42	31	34	31	29	28	27	25	23	22	21	526	796
	DSM, Class 2, WY	4	4	5	5	6	6	7	7	7	8	7	7	7	7	8	7	7	8	8	8	59	133
	DSM, Class 2 Total	74	68	64	63	63	62	60	55	55	54	41	44	40	40	39	37	35	33	32	32	618	991
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	0.4	0.3	0.4	0.5	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	12	118	212	-	117	208	236	76	194	53	146	240	53	53	163	46	94
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Utility Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	5
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	11	21
	DSM, Class 2, OR	37	41	34	34	31	32	28	24	24	26	26	26	26	26	26	26	26	26	26	26	311	568
	DSM, Class 2, WA	8	8	8	8	8	7	7	7	7	7	5	5	5	5	5	4	4	4	4	4	76	120
	DSM, Class 2 Total	46	50	43	43	40	40	36	33	32	34	33	32	32	32	32	31	30	30	30	30	398	710
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	95	210	297	297	297	277	297	297	297	297	297	220	297	297	247	293	297	177	230
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	170	229	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	360	380
	FOT MidColumbia Q3 - 2	375	375	337	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	371	373
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	-	(387)	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	146	778	125	193	173	162	620	102	103	105	90	342	956	88	510	745	82	1,152	79	115		
	Annual Additions, Short Term Resources	645	704	837	970	1,085	1,184	1,290	1,384	1,152	1,289	1,380	1,408	1,248	1,366	1,148	1,318	1,412	1,175	1,221	1,335		
	Total Annual Additions	791	1,482	962	1,163	1,258	1,346	1,910	1,486	1,255	1,394	1,470	1,750	2,204	1,454	1,658	2,063	1,494	2,327	1,300	1,450		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

EG-2 Case S-10		Capacity (MW)																				Resource Totals 1/	
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(43)	-	-	(43)
	Hayden2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	(30)
	Carbon1 (Early Retirement/Conversion)	-	-	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon2 (Early Retirement/Conversion)	-	-	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla1 (Early Retirement/Conversion)	-	-	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	(387)
	Johnston1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	(106)
	Johnston3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	(220)
	Johnston4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(328)	-	-	-	-	-	(328)
	Naughton1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(158)	-	-	-	(158)
	Naughton2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(205)	-	-	-	(205)
	Naughton3 (Early Retirement/Conversion)	-	-	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Coal Ret_WY - Gas RePower	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(338)	-	-	338	-
	Expansion Resources																						
	CCCT FD 2x1	-	-	-	-	-	-	-	-	-	-	-	661	-	-	-	661	-	-	-	-	-	1,322
	CCCT GH 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	736	-	-	-	736
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645	645
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	-	-	181
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	Wind, GO, 29	-	-	-	73	34	33	14	-	-	45	5	-	-	-	-	-	-	-	-	-	199	204
	Wind, UT, 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	22
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	368	282	-	-	-	-	-	-	-	-	650
	Total Wind	-	-	-	73	34	33	14	-	-	45	5	368	282	-	-	-	-	-	-	22	199	876
	CHP - Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.6	3.2
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.0	6.6	-	13.6
	CHP - Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.7	2.4	2.7	2.7	2.7	3.6	16.6
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	1	-	9
	DSM, Class 1, ID-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	-	44	37	-	3	-	91
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	-	14	4	-	26
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	13	-	-	2	-	25
	DSM, Class 1, WY-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	0	-	4
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	0	-	-	0	-	0
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	10	64	37	19	11	-	158
	DSM, Class 2, ID	3	3	3	3	3	3	4	3	4	4	3	3	3	3	3	3	3	3	3	3	30	59
	DSM, Class 2, UT	63	61	54	51	49	48	45	43	42	40	30	33	30	28	27	25	23	22	22	21	495	756
	DSM, Class 2, WY	4	4	5	5	6	6	6	6	7	7	6	7	6	7	8	7	7	7	8	8	55	127
	DSM, Class 2 Total	69	67	61	59	57	56	55	52	52	51	39	42	39	38	37	35	34	32	32	32	581	942
	DSM, Class 3, UT Res TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3	-	6
	DSM, Class 3, WY IRR TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	-	0
	DSM, Class 3 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3	-	6
	Micro Solar - PV	7.11	11.0	14.2	16.4	17.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	131	262
	Micro Solar - Water Heating	-	-	-	-	-	-	1.6	0.6	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	7.0	30.6
	FOT Mona Q3	-	-	-	-	-	41	159	257	28	169	263	64	258	220	300	300	300	295	300	300	65	163
West	**Expansion Resources**																						
	Coal Plant Turbine Upgrades	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	SCCT Frame WW	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	-	-	-	-	-	197
	CHP - Biomass	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	5.5	11.0
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4	0.2	-	1.6
	CHP - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	0.3	-	0.5
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	-	22	-	-	3	-	46
	DSM, Class 1, OR-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	15	-	29
	DSM, Class 1, OR-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	3
	DSM, Class 1, CA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	4
	DSM, Class 1, CA-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	0	-	1
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	0	-	2
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	1	22	-	15	18	-	86
	DSM, Class 2, CA	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	10	19
	DSM, Class 2, OR	36	41	33	32	29	26	22	21	20	23	23	22	22	22	22	26	26	26	26	26	284	523
	DSM, Class 2, WA	8	7	7	7	7	6	6	6	6	6	4	4	4	4	4	3	3	3	3	3	67	104
	DSM, Class 2 Total	45	49	41	41	38	33	29	28	27	30	28	27	27	27	27	30	30	30	30	30	360	646
	DSM, Class 3, CA IRR TOU	-	-	-	-	-	-	-	-	-	-	1	-	-	-	1	-	-	-	-	-	-	1
	DSM, Class 3, OR IRR TOU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	2
	DSM, Class 3 Total	-	-	-	-	-	-	-	-	-	-	1	-	-	-	2	1	-	-	-	-	-	4
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	4.45	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	FOT COB Q3	-	-	-	109	230	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	182	240
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	387	400	393	400	400	400	397	400	399
	FOT MidColumbia Q3 - 2	150	209	345	375	375	375	375	375	375	375	375	375	375	375	366	375	375	375	371	375	333	353
	Existing Plant Retirements/Conversions	-	-	(164)	-	-	-	-	-	-	-	-	(387)	-	-	-	(760)	-	(701)	(74)	-		
	Annual Additions, Long Term Resources	140	776	121	190	147	137	114	95	96	143	90	1,115	364	279	132	937	169	853	130	235		
	Annual Additions, Short Term Resources	650	709	845	984	1,105	1,213	1,331	1,429	1,200	1,341	1,435	1,236	1,430	1,379	1,463	1,465	1,472	1,467	1,468	1,469		
	Total Annual Additions	790	1,485	966	1,174	1,252	1,350	1,445	1,524	1,296	1,484	1,525	2,351	1,794	1,658	1,595	2,402	1,641	2,320	1,598	1,704		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

APPENDIX L – 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 Energy Gateway scenarios 1 and 2 for all core cases. These results supplement the data presented in Chapter 8 of the main IRP document. The results presented include the following:

- Stochastic mean present value of revenue requirements (PVRR) versus upper-tail mean less stochastic mean PVRR scatter-plot diagrams that include all carbon dioxide (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.
- EG2 - Case C07a is the preferred portfolio.

Core Case Study Stochastic Results

Mean versus Upper-tail Mean PVRR Scatter-plot Charts

The following set of scatter plot charts (Figures L.1 through L.6) incorporates all core cases for zero, medium, and high, CO_2 tax scenarios and for Energy Gateway (EG) scenarios 1 and 2 as applicable[64].

Stochastic Risk and Other Portfolio Performance Measures

The following set of tables (Tables L.1 through L.8) show the stochastic risk and other portfolio performance measures as follows:

- Table L.1 - Stochastic Mean PVRR by CO_2 Tax Level, Core Case Portfolios
- Table L.2 - Stochastic Risk Results by CO_2 Tax Level, Core Case Portfolios
- Table L.3 - Stochastic Risk Adjusted PVRR by CO_2 Tax Level, Core Case Portfolios
- Table L.4 - Carbon Dioxide Emissions by CO2 Tax Level, Core Case Portfolios
- Table L.5 - 10-Year Average Incremental Customer Rate Impact, Final Screen Portfolios
- Table L.6 - Average Annual Energy Not served (2013 – 2032), Medium CO_2 Initial Screen Portfolios
- Table L.7 - Loss of Load Probability for Major (25,000 MWh) July Event
- Table L.8 - Average Loss of Load Probability during Summer Peak

Tables L.9 through L.11 report the breakdown of each portfolio's stochastic mean PVRR by variable and fixed cost components. These costs reflect the medium, zero, and high ton CO_2 cost scenario.

[64] Core case 19 is not applicable to Energy Gateway scenario 1.

Figure L.1 – Stochastic Risk Profile, Zero CO_2 Scenario, Energy Gateway Scenario 1

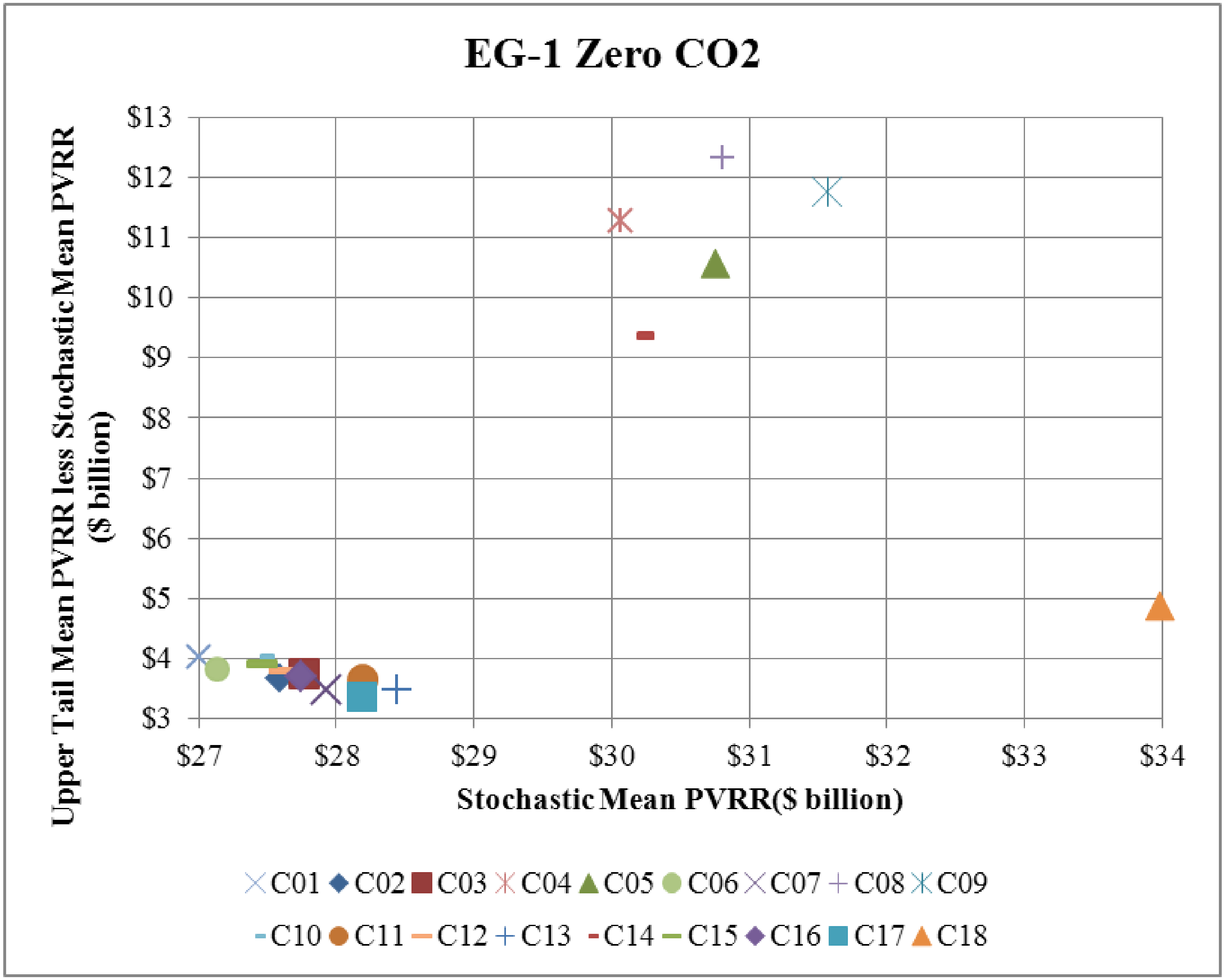


Figure L.2 – Stochastic Risk Profile, Medium CO_2 Scenario, Energy Gateway Scenario 1

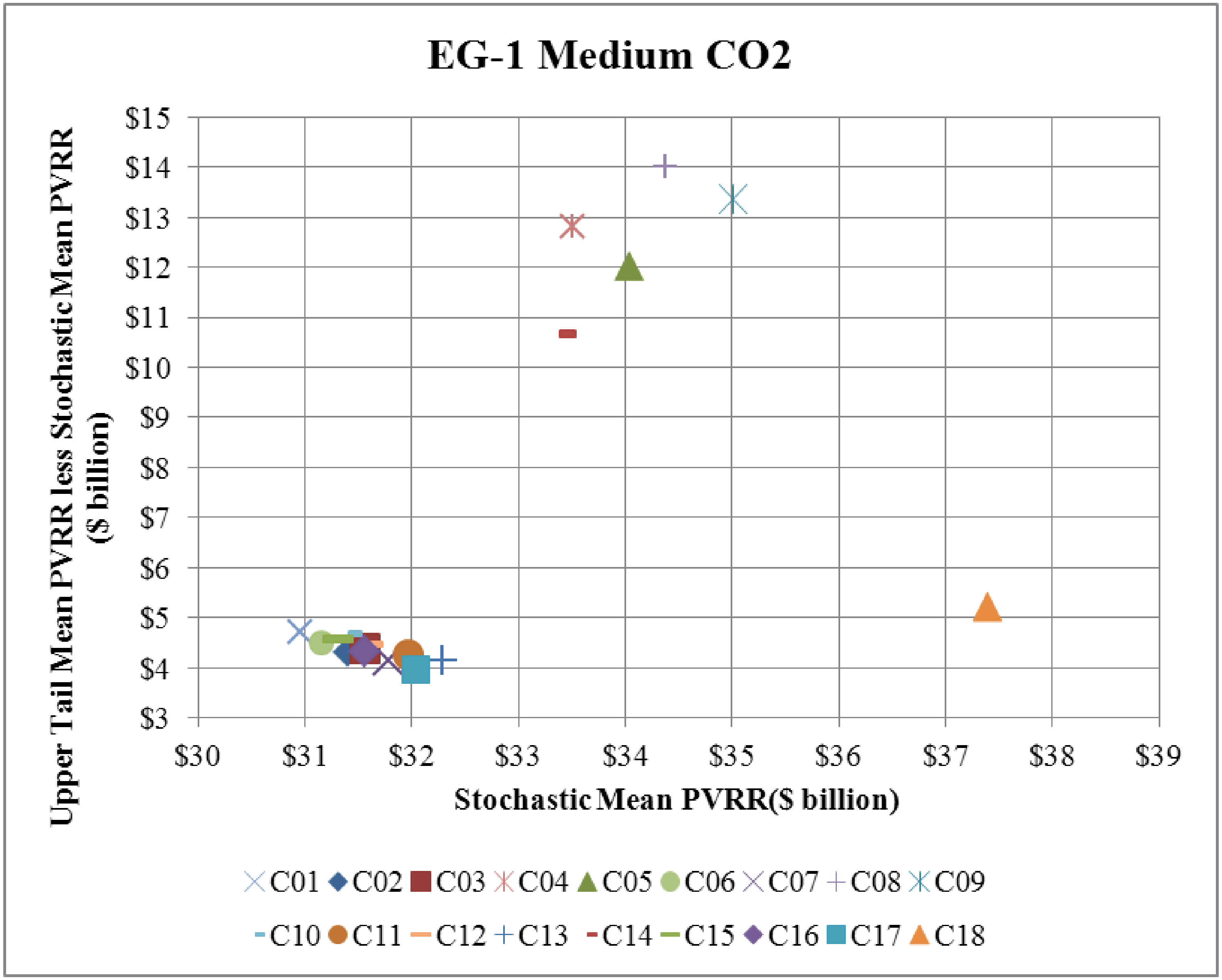


Figure L.3 – Stochastic Risk Profile, High CO_2 Scenario, Energy Gateway Scenario 1

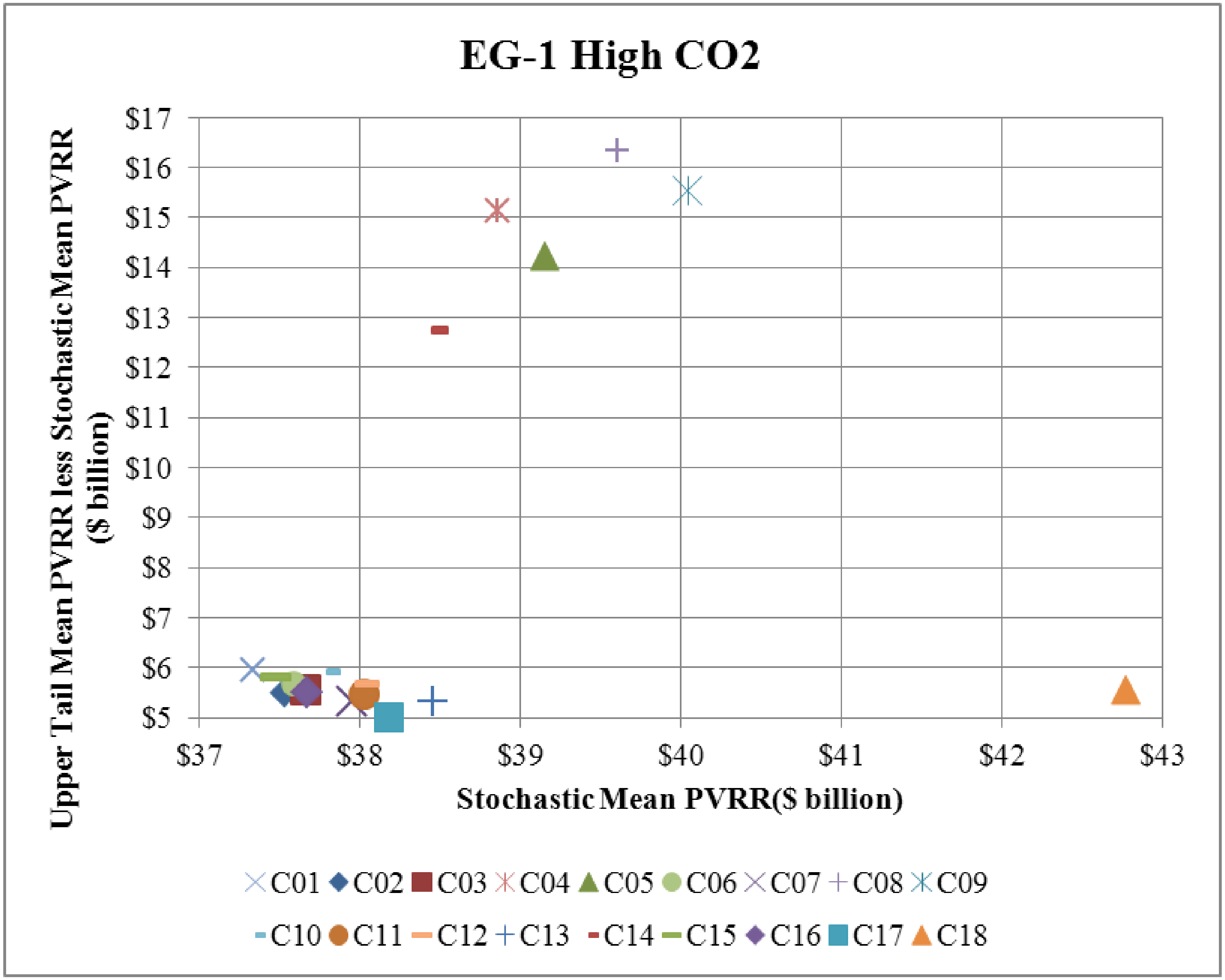


Figure L.4 – Stochastic Risk Profile, Zero CO_2 Scenario, Energy Gateway Scenario 2

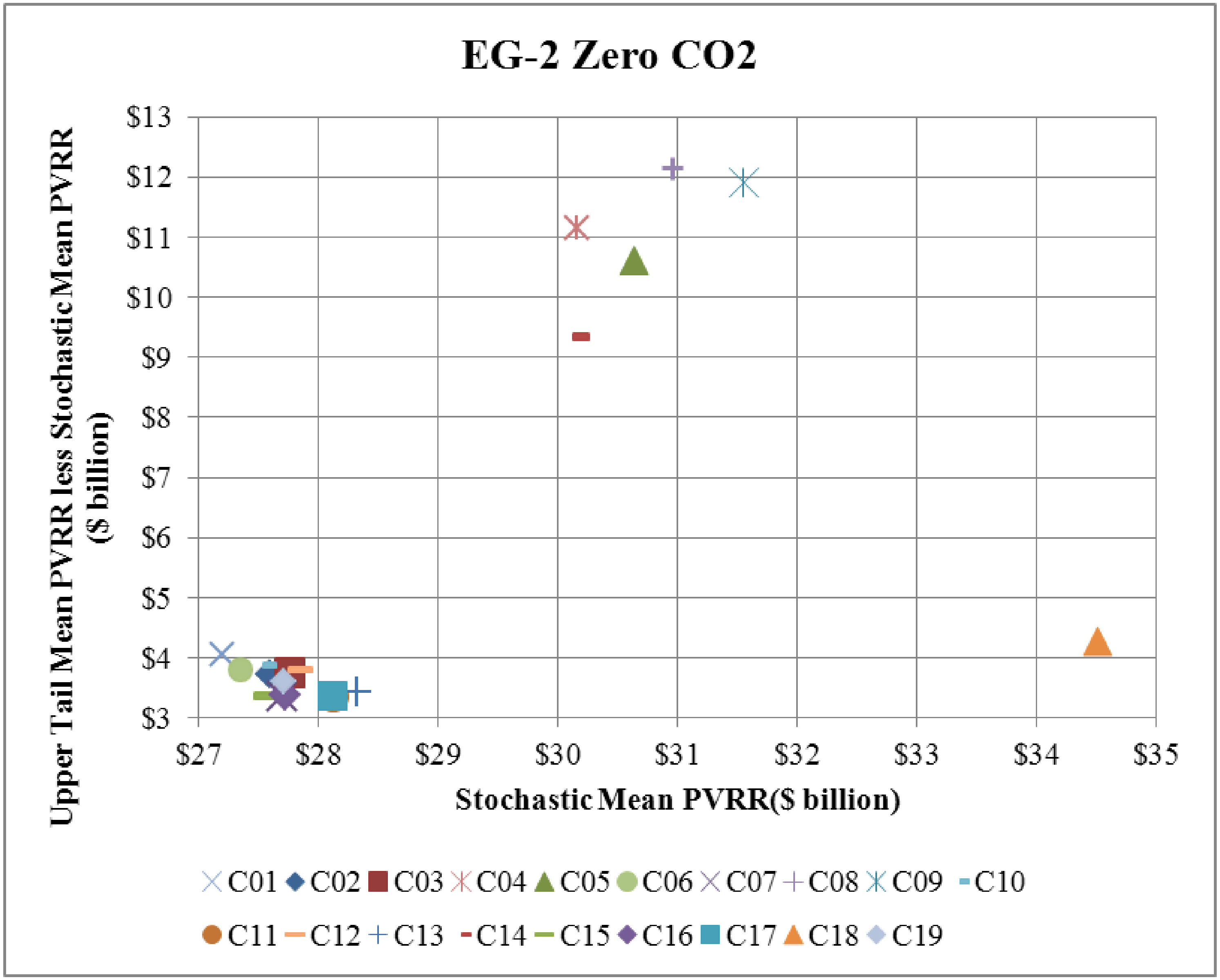


Figure L.5 – Stochastic Risk Profile, Medium CO_2 Scenario, Energy Gateway Scenario 2

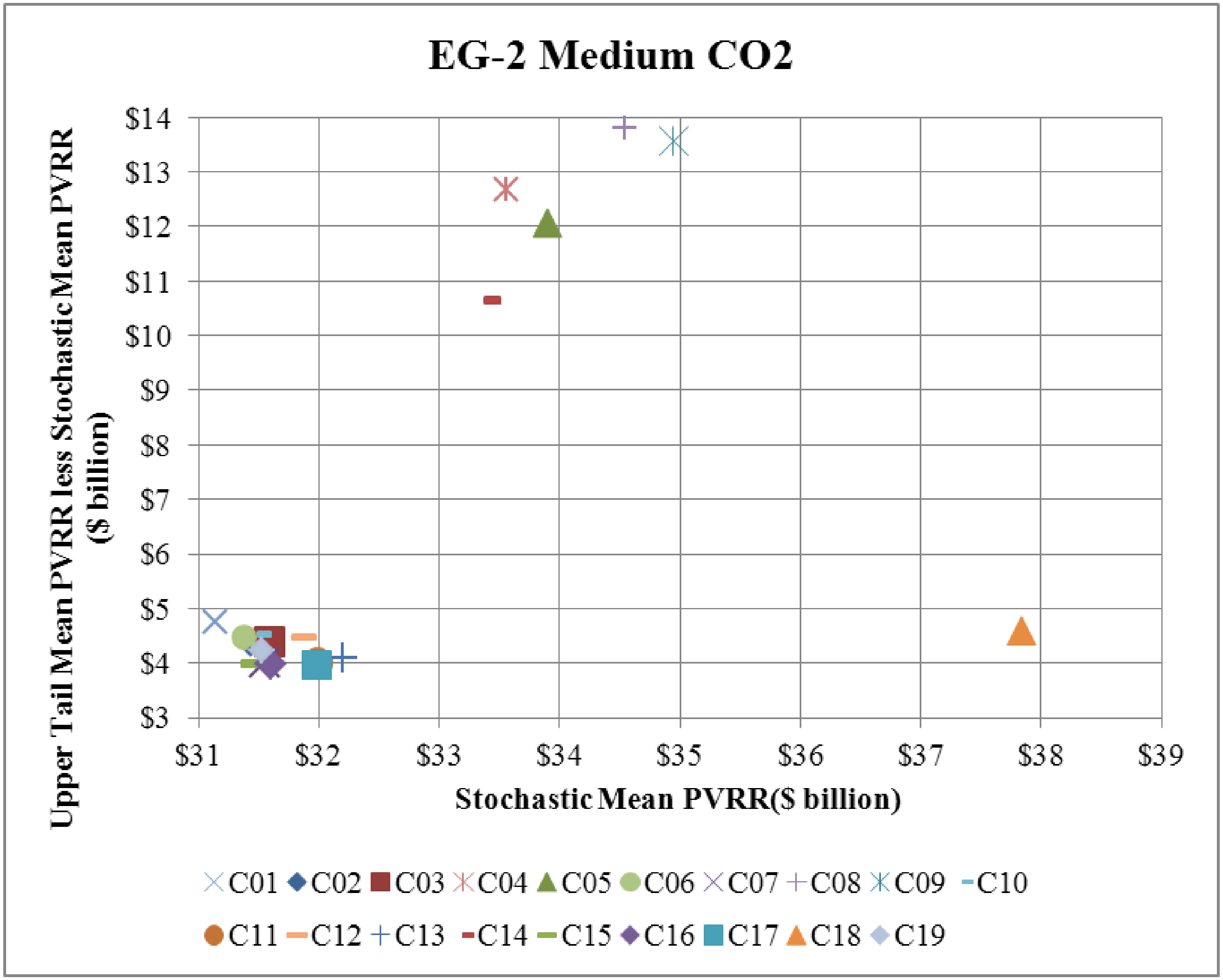

EG-2 Medium CO2
Upper Tail Mean PVRR less Stochastic Mean PVRR ($ billion)
$14
$13
$12
$11
$10
$9
$8
$7
$6
$5
$4
$3
$31
$32
$33
$34
$35
$36
$37
$38
$39
Stochastic Mean PVRR($ billion)
C01 C02 C03 C04 C05 C06 C07 C08 C09 C10
C11 C12 C13 C14 C15 C16 C17 C18 C19

Figure L.6 – Stochastic Risk Profile, High CO_2 Scenario, Energy Gateway Scenario 2

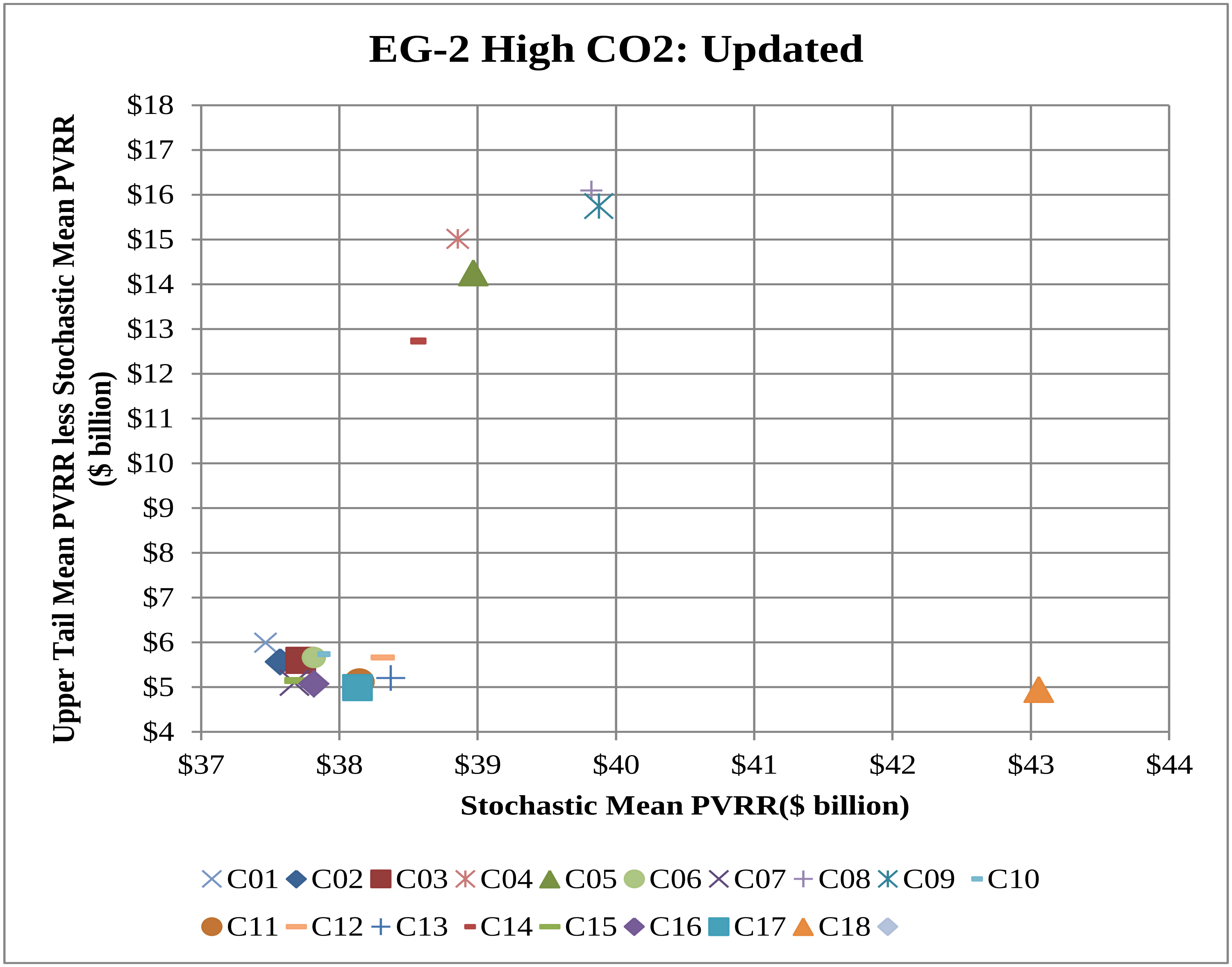


Table L.1– Stochastic Mean PVRR by CO_2 Tax Level, Core Case Portfolios

EG1	CO_2 tax level Million Dollars (2013$)			
Case	**Zero**	**Medium**	**High**	**Average**
C01	27,004	30,964	37,337	31,768
C02	27,586	31,397	37,534	32,172
C03	27,766	31,557	37,668	32,330
C04	30,071	33,507	38,860	34,146
C05	30,754	34,035	39,155	34,648
C06	27,132	31,159	37,593	31,961
C07	27,935	31,789	37,953	32,559
C08	30,810	34,378	39,613	34,934
C09	31,570	35,009	40,046	35,542
C10	27,461	31,425	37,803	32,230
C11	28,190	31,966	38,027	32,728
C12	27,603	31,615	38,046	32,421
C13	28,439	32,293	38,460	33,064
C14	30,203	33,401	38,461	34,022
C15	27,457	31,308	37,483	32,083
C16	27,748	31,556	37,677	32,327
C17	28,186	32,036	38,184	32,802
C18	33,984	37,390	42,774	38,049

EG2	CO_2 tax level Million Dollars (2013$)			
Case	**Zero**	**Medium**	**High**	**Average**
C01	27,202	31,138	37,468	31,936
C02	27,593	31,432	37,571	32,199
C03	27,770	31,596	37,722	32,363
C04	30,162	33,554	38,858	34,191
C05	30,640	33,898	38,968	34,502
C06	27,359	31,376	37,816	32,184
C07	27,708	31,556	37,677	32,314
C07a	27,466	31,357	37,546	32,123
C08	30,965	34,548	39,822	35,112
C09	31,554	34,944	39,877	35,458
C10	27,559	31,501	37,849	32,303
C11	28,132	31,986	38,146	32,755
C12	27,855	31,874	38,315	32,681
C13	28,333	32,202	38,373	32,969
C14	30,142	33,384	38,520	34,015
C15	27,588	31,480	37,716	32,261
C16	27,729	31,607	37,817	32,384
C17	28,118	31,985	38,132	32,745
C18	34,509	37,836	43,058	38,468
C19	27,715	31,528	37,630	32,291

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

EG1	CO_2 tax level: Zero Million Dollars (2013$)			
Case	Standard Deviation	5th percentile	95th percentile	Upper Tail (mean of 5 Highest)
C01	1,567	24,589	29,880	31,038
C02	1,446	25,322	30,146	31,270
C03	1,462	25,611	30,307	31,508
C04	4,211	24,301	38,116	41,336
C05	3,963	25,458	38,431	41,326
C06	1,518	24,793	29,839	30,946
C07	1,416	25,697	30,485	31,424
C08	4,617	24,521	39,449	43,124
C09	4,412	25,624	39,789	43,323
C10	1,568	25,029	30,197	31,481
C11	1,430	25,970	30,697	31,833
C12	1,512	25,262	30,294	31,407
C13	1,397	26,290	30,898	31,928
C14	3,493	25,360	36,960	39,557
C15	1,477	25,182	30,021	31,364
C16	1,449	25,538	30,285	31,451
C17	1,372	26,122	30,812	31,561
C18	1,852	31,113	37,170	38,863

EG2	CO_2 tax level: Zero Million Dollars (2013$)			
Case	Standard Deviation	5th percentile	95th percentile	Upper Tail (mean of 5 Highest)
C01	1,559	24,792	29,910	31,255
C02	1,453	25,367	30,162	31,328
C03	1,470	25,498	30,356	31,516
C04	4,155	24,420	38,070	41,313
C05	3,972	25,108	38,247	41,255
C06	1,503	25,041	30,018	31,153
C07	1,357	25,577	30,159	31,060
C07a	1,387	25,282	29,991	30,913
C08	4,544	24,781	39,379	43,102
C09	4,473	25,384	39,770	43,469
C10	1,507	25,222	30,253	31,447
C11	1,353	26,035	30,614	31,496
C12	1,502	25,550	30,557	31,647
C13	1,380	26,182	30,780	31,770
C14	3,499	25,313	36,956	39,472
C15	1,292	25,571	29,902	30,937
C16	1,352	25,609	30,198	31,101
C17	1,371	26,050	30,785	31,485
C18	1,616	32,156	37,444	38,786
C19	1,420	25,516	30,228	31,311

Table L.2 – Stochastic Risk Results by CO_2 Tax Level, Core Case Portfolios (Continued)

EG1	CO_2 tax level: Medium Million Dollars (2013$)			
Case	Standard Deviation	5th percentile	95th percentile	Upper Tail (mean of 5 Highest)
C01	1,901	28,000	34,234	35,666
C02	1,774	28,654	34,284	35,714
C03	1,788	28,787	34,439	35,937
C04	4,758	27,007	42,624	46,307
C05	4,481	27,979	42,725	46,056
C06	1,867	28,211	34,301	35,648
C07	1,768	29,012	34,644	35,937
C08	5,225	27,268	44,142	48,397
C09	4,992	28,290	44,318	48,382
C10	1,902	28,465	34,569	36,108
C11	1,762	29,253	34,840	36,237
C12	1,858	28,692	34,688	36,096
C13	1,749	29,537	35,105	36,444
C14	3,951	27,921	41,046	44,056
C15	1,793	28,480	34,160	35,883
C16	1,774	28,805	34,417	35,885
C17	1,698	29,135	34,973	36,001
C18	2,067	34,007	40,788	42,609

EG2	CO_2 tax level: Medium Million Dollars (2013$)			
Case	Standard Deviation	5th percentile	95th percentile	Upper Tail (mean of 5 Highest)
C01	1,882	28,213	34,172	35,876
C02	1,778	28,697	34,303	35,817
C03	1,802	28,830	34,518	35,999
C04	4,697	27,082	42,534	46,234
C05	4,489	27,676	42,521	45,965
C06	1,848	28,484	34,467	35,856
C07	1,693	28,925	34,363	35,552
C07a	1,723	28,646	34,208	35,452
C08	5,145	27,579	44,113	48,357
C09	5,055	27,995	44,226	48,502
C10	1,822	28,658	34,480	36,044
C11	1,686	29,350	34,774	35,988
C12	1,844	28,978	34,912	36,352
C13	1,718	29,513	35,048	36,287
C14	3,968	27,898	41,145	44,013
C15	1,602	28,945	34,077	35,460
C16	1,672	28,990	34,399	35,598
C17	1,691	29,119	34,961	35,960
C18	1,822	34,875	41,003	42,433
C19	1,745	28,822	34,374	35,766

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

EG1	CO_2 tax level: High Million Dollars (2013$)			
Case	Standard Deviation	5th percentile	95th percentile	Upper Tail (mean of 5 Highest)
C01	2,536	33,038	41,380	43,283
C02	2,395	33,440	41,234	43,034
C03	2,415	33,497	41,370	43,236
C04	5,574	31,116	49,612	53,982
C05	5,251	31,847	49,331	53,383
C06	2,495	33,323	41,547	43,281
C07	2,396	33,794	41,757	43,258
C08	6,028	31,282	51,008	55,959
C09	5,744	32,107	50,881	55,590
C10	2,536	33,521	41,777	43,722
C11	2,388	33,916	41,745	43,489
C12	2,485	33,848	41,924	43,718
C13	2,373	34,416	42,156	43,767
C14	4,681	31,997	47,553	51,186
C15	2,405	33,371	41,144	43,271
C16	2,391	33,537	41,360	43,180
C17	2,287	34,167	41,832	43,196
C18	2,421	38,585	46,646	48,335

EG2	CO_2 tax level: High Million Dollars (2013$)			
Case	Standard Deviation	5th percentile	95th percentile	Upper Tail (mean of 5 Highest)
C01	2,494	33,153	41,348	43,454
C02	2,391	33,436	41,277	43,136
C03	2,423	33,614	41,468	43,314
C04	5,509	31,249	49,342	53,868
C05	5,254	31,712	49,030	53,226
C06	2,462	33,582	41,692	43,471
C07	2,291	33,660	41,316	42,769
C07a	2,321	33,521	41,244	42,744
C08	5,943	31,775	51,014	55,919
C09	5,815	31,862	50,747	55,625
C10	2,430	33,753	41,629	43,582
C11	2,285	34,181	41,782	43,257
C12	2,460	34,091	42,146	43,973
C13	2,314	34,368	42,039	43,575
C14	4,715	32,045	47,750	51,243
C15	2,205	33,865	41,187	42,852
C16	2,253	33,897	41,392	42,888
C17	2,262	34,147	41,776	43,123
C18	2,171	39,278	46,455	48,006
C19	2,356	33,570	41,308	43,024

Table L.3– Stochastic Risk Adjusted PVRR by CO_2 Tax Level

		Risk-adjusted PVRR [Mean + .05 * 95th] CO2 Tax Scenario $/Ton			
EG Scenario	Case	Zero	Medium	High	Average
EG1	C01	27,997	32,175	38,905	33,026
EG1	C02	28,542	32,560	39,044	33,382
EG1	C03	28,719	32,717	39,175	33,537
EG1	C04	31,485	35,146	40,848	35,826
EG1	C05	32,122	35,618	41,068	36,269
EG1	C06	28,119	32,368	39,165	33,217
EG1	C07	28,894	32,956	39,476	33,775
EG1	C08	32,285	36,088	41,666	36,680
EG1	C09	33,002	36,668	42,033	37,234
EG1	C10	28,446	32,628	39,366	33,480
EG1	C11	29,140	33,123	39,529	33,931
EG1	C12	28,588	32,820	39,612	33,673
EG1	C13	29,393	33,458	39,978	34,277
EG1	C14	31,500	34,902	40,288	35,563
EG1	C15	28,413	32,471	38,996	33,293
EG1	C16	28,703	32,718	39,186	33,536
EG1	C17	29,146	33,203	39,694	34,014
EG1	C18	35,026	38,613	44,290	39,310

		Risk-adjusted PVRR [Mean + .05 * 95th] CO2 Tax Scenario $/Ton			
EG Scenario	Case	Zero	Medium	High	Average
EG2	C01	28,151	32,300	38,989	33,147
EG2	C02	28,517	32,563	39,050	33,376
EG2	C03	28,695	32,729	39,203	33,542
EG2	C04	31,529	35,145	40,789	35,821
EG2	C05	31,967	35,439	40,835	36,080
EG2	C06	28,310	32,549	39,350	33,403
EG2	C07	28,621	32,679	39,149	33,483
EG2	C07a	28,639	32,663	39,116	33,473
EG2	C08	32,389	36,208	41,827	36,808
EG2	C09	32,957	36,571	41,830	37,119
EG2	C10	28,505	32,658	39,363	33,508
EG2	C11	29,045	33,108	39,618	33,924
EG2	C12	28,808	33,045	39,847	33,900
EG2	C13	29,253	33,334	39,856	34,148
EG2	C14	31,407	34,859	40,325	35,530
EG2	C15	28,494	32,595	39,186	33,425
EG2	C16	28,646	32,735	39,295	33,558
EG2	C17	29,044	33,120	39,607	33,924
EG2	C18	35,477	38,982	44,476	39,645
EG2	C19	28,633	32,654	39,102	33,463

Table L.4 – Carbon Dioxide Emissions

EG1	Cummulative Carbon Dioxide Emissions for 2013 - 2032 (Short Tons) CO2 tax level											
Case	Zero	Cost Spread Relative to Lowest Case	Rank	Medium	Cost Spread Relative to Lowest Case	Rank	High	Cost Spread Relative to Lowest Case	Rank	Average	Cost Spread Relative to Lowest Case	Rank
C01	887,205	293,696	14	851,682	272,976	14	820,408	249,166	14	853,098	271,946	14
C02	874,178	280,669	11	837,578	258,873	11	805,381	234,139	11	839,046	257,894	11
C03	871,984	278,475	9	836,154	257,448	9	803,958	232,717	9	837,365	256,213	9
C04	634,787	41,278	4	620,712	42,006	4	610,174	38,932	4	621,891	40,739	4
C05	628,979	35,470	3	615,020	36,315	3	604,101	32,859	3	616,033	34,881	3
C06	898,540	305,031	18	860,125	281,419	17	828,295	257,054	17	862,320	281,168	17
C07	884,725	291,216	13	845,061	266,356	12	811,879	240,638	12	847,222	266,070	12
C08	604,917	11,408	2	589,900	11,194	2	582,215	10,973	2	592,344	11,192	2
C09	593,509	0	1	578,705	0	1	571,242	0	1	581,152	0	1
C10	887,337	293,828	15	851,922	273,216	15	820,869	249,628	15	853,376	272,224	15
C11	871,047	277,538	8	833,753	255,048	8	801,042	229,800	7	835,280	254,128	8
C12	898,486	304,977	17	860,758	282,053	18	829,118	257,876	18	862,787	281,635	18
C13	884,686	291,177	12	845,088	266,382	13	811,937	240,695	13	847,237	266,085	13
C14	656,665	63,156	5	642,532	63,827	5	630,718	59,476	5	643,305	62,153	5
C15	862,764	269,254	7	831,381	252,676	7	802,982	231,740	8	832,375	251,223	7
C16	873,506	279,997	10	836,778	258,073	10	804,491	233,249	10	838,258	257,106	10
C17	896,136	302,627	16	857,056	278,350	16	824,668	253,426	16	859,286	278,134	16
C18	784,248	190,739	6	757,244	178,539	6	727,457	156,216	6	756,317	175,164	6

EG2	Cummulative Carbon Dioxide Emissions for 2013 - 2032 (Short Tons) CO2 tax level											
Case	Zero	Cost Spread Relative to Lowest Case	Rank	Medium	Cost Spread Relative to Lowest Case	Rank	High	Cost Spread Relative to Lowest Case	Rank	Average	Cost Spread Relative to Lowest Case	Rank
C01	889,148	296,180	15	855,657	276,602	17	825,416	253,892	17	856,740	275,558	17
C02	876,193	283,225	9	841,021	261,966	9	809,731	238,207	9	842,315	261,133	9
C03	873,964	280,996	7	837,300	258,245	8	804,480	232,956	7	838,581	257,399	7
C04	642,874	49,907	4	629,200	50,145	4	618,391	46,867	4	630,155	48,973	4
C05	632,540	39,573	3	619,210	40,155	3	608,417	36,893	3	620,056	38,874	3
C06	899,552	306,584	20	862,337	283,281	19	830,971	259,447	19	864,286	283,104	19
C07	884,841	291,873	10	845,998	266,942	10	813,184	241,660	10	848,008	266,825	10
C07a	889,291	296,324	16	851,000	271,945	13	818,735	247,211	13	853,009	271,827	13
C08	608,294	15,327	2	593,165	14,110	2	584,787	13,263	2	595,416	14,233	2
C09	592,968	0	1	579,055	0	1	571,524	0	1	581,182	0	1
C10	887,424	294,456	13	854,002	274,947	15	823,761	252,237	15	855,062	273,880	15
C11	886,356	293,389	12	848,108	269,053	12	815,771	244,247	12	850,079	268,896	12
C12	899,509	306,541	19	862,425	283,370	20	830,975	259,450	20	864,303	283,120	20
C13	886,118	293,150	11	847,343	268,288	11	814,289	242,765	11	849,250	268,068	11
C14	655,509	62,542	5	639,325	60,270	5	625,810	54,285	5	640,215	59,032	5
C15	889,384	296,417	17	855,418	276,363	16	824,930	253,406	16	856,578	275,395	16
C16	888,635	295,667	14	851,427	272,372	14	820,124	248,600	14	853,395	272,213	14
C17	897,356	304,388	18	858,353	279,298	18	825,533	254,009	18	860,414	279,232	18
C18	785,096	192,128	6	755,983	176,928	6	724,551	153,026	6	755,210	174,028	6
C19	874,360	281,392	8	837,127	258,072	7	804,536	233,011	8	838,674	257,492	8

Table L.5 –10-year Average Incremental Customer Rate Impact, Final Screen Portfolios

	10-year Average Incremental Customer Rate Impact (2013 - 2022)									
	Zero		Medium		High					
$ Millions	Difference from C07	Rank	Difference from C07	Rank	Difference from C07	Rank	Total	Average	Difference from C07	Rank
EG1										
C03	0.0	3	0.2	3	0.2	3	0.3	0.1	0.1	3
C07	0.0	2	0.0	2	0.0	2	0.0	0.0	0.0	2
C15	(7.3)	1	(9.4)	1	(10.1)	1	(26.9)	(9.0)	(9.0)	1
C16	2.9	4	2.7	4	2.4	4	8.0	2.7	2.7	4
C17	5.8	5	5.2	5	4.6	5	15.7	5.2	5.2	5
	Difference from C07a	Rank	Difference from C07a	Rank	Difference from C07a	Rank	Total	Average	Difference from C07a	Rank
EG2										
C03	5.4	4	4.9	4	4.3	4	14.6	4.9	4.9	4
C07	5.5	5	4.7	3	4.2	3	14.4	4.8	4.8	3
C07a	0.0	1	0.0	1	0.0	2	0.0	0.0	0.0	1
C15	1.8	2	0.1	2	(1.6)	1	0.3	0.1	0.1	2
C16	5.4	3	4.9	5	4.6	5	14.9	5.0	5.0	5
C17	10.8	6	9.6	6	8.4	6	28.8	9.6	9.6	6

Table L.6 – Average Annual Energy Not Served (2013 – 2032), Medium CO_2 Initial Screen Portfolios

EG1	Averaged Annual Energy Not Served (GWh) CO2 tax level: Medium					
Preferred Case	Average Annual Energy Not Served, 2013-2032 (GWh)	Cost Spread Relative to Lowest Case	Rank	Upper Tail Mean Energy Not Served Cumulative Total, 2013-2032	Cost Spread Relative to Lowest Case	Rank
C01	52.6	17.6	7	90.0	33.9	11
C02	41.7	6.7	2	65.6	9.5	2
C03	46.0	11.1	6	70.9	14.8	3
C04	54.2	19.3	9	83.0	26.9	7
C05	56.9	22.0	12	87.3	31.3	10
C06	57.0	22.0	13	117.9	61.9	18
C07	58.8	23.8	14	104.2	48.2	15
C08	53.7	18.7	8	85.8	29.7	9
C09	59.4	24.4	15	91.9	35.8	12
C10	45.7	10.7	5	77.4	21.3	6
C11	42.3	7.3	3	73.0	17.0	4
C12	54.9	19.9	10	100.8	44.8	13
C13	61.1	26.2	16	103.8	47.8	14
C14	56.6	21.6	11	85.1	29.0	8
C15	35.0	0.0	1	56.1	0.0	1
C16	44.3	9.3	4	77.3	21.2	5
C17	63.6	28.6	17	105.1	49.0	16
C18	65.1	30.1	18	116.3	60.3	17

Table L.6 – Average Annual Energy Not Served (2013 – 2032), Medium CO_2 Initial Screen Portfolios (Continued)

EG2	Averaged Annual Energy Not Served (GWh) CO2 tax level: Medium					
Preferred Case	**Average Annual Energy Not Served, 2013-2032 (GWh)**	**Cost Spread Relative to Lowest Case**	**Rank**	**Upper Tail Mean Energy Not Served Cumulative Total, 2013-2032**	**Cost Spread Relative to Lowest Case**	**Rank**
C01	44.5	5.8	5	83.2	17.1	11
C02	38.8	0.0	1	79.4	13.4	10
C03	45.6	6.9	7	75.4	9.3	8
C04	49.6	10.9	14	71.8	5.8	5
C05	48.3	9.6	13	66.2	0.2	2
C06	53.3	14.5	16	98.4	32.4	17
C07	46.6	7.8	8	89.3	23.3	15
C07a	46.8	8.1	9	89.0	23.0	14
C08	47.5	8.7	11	67.9	1.9	3
C09	48.3	9.6	12	70.8	4.8	4
C10	41.2	2.5	2	73.8	7.8	6
C11	43.3	4.5	4	74.5	8.5	7
C12	54.3	15.6	19	103.0	37.0	19
C13	50.5	11.7	15	91.3	25.3	16
C14	46.9	8.1	10	66.0	0.0	1
C15	53.6	14.9	17	86.3	20.3	13
C16	45.6	6.9	6	84.3	18.3	12
C17	55.8	17.1	20	99.2	33.2	18
C18	54.0	15.2	18	104.7	38.7	20
C19	42.0	3.2	3	75.9	9.9	9

Table L.7 – Loss of Load Probability for a Major (> 25,000 MWh) July Event

EG1						
Year	**C03**	**C07**	**C11**	**C15**	**C16**	**C17**
2013	1%	1%	1%	1%	1%	1%
2014	0%	0%	1%	0%	0%	0%
2015	1%	1%	1%	2%	1%	1%
2016	2%	3%	2%	2%	3%	2%
2017	5%	5%	5%	5%	5%	5%
2018	37%	37%	37%	37%	37%	37%
2019	19%	19%	20%	19%	19%	20%
2020	5%	5%	6%	5%	5%	6%
2021	2%	2%	3%	2%	3%	4%
2022	11%	11%	12%	6%	11%	10%
2023	11%	13%	12%	6%	12%	12%
2024	17%	17%	21%	7%	22%	20%
2025	3%	4%	3%	2%	2%	7%
2026	2%	6%	2%	4%	6%	4%
2027	3%	3%	3%	4%	3%	6%
2028	3%	10%	7%	3%	4%	11%
2029	10%	18%	11%	6%	8%	19%
2030	13%	25%	8%	10%	10%	21%
2031	3%	12%	0%	5%	2%	13%
2032	5%	9%	4%	8%	5%	13%

EG2							
Year	C03	C07	C07a	C11	C15	C16	C17
2013	1%	1%	1%	1%	1%	1%	1%
2014	0%	0%	0%	0%	0%	0%	0%
2015	1%	2%	1%	1%	1%	1%	1%
2016	2%	3%	2%	3%	2%	2%	2%
2017	5%	5%	6%	5%	4%	5%	5%
2018	37%	37%	37%	37%	35%	38%	38%
2019	19%	19%	21%	19%	18%	19%	19%
2020	5%	5%	5%	5%	5%	6%	5%
2021	2%	2%	3%	2%	3%	3%	2%
2022	11%	11%	12%	11%	10%	12%	11%
2023	11%	14%	12%	12%	12%	14%	13%
2024	17%	17%	20%	22%	22%	25%	20%
2025	3%	4%	4%	6%	6%	8%	10%
2026	5%	8%	10%	6%	9%	9%	8%
2027	5%	10%	13%	3%	13%	14%	14%
2028	2%	3%	3%	2%	7%	2%	7%
2029	11%	7%	11%	5%	13%	5%	18%
2030	14%	12%	12%	14%	19%	11%	18%
2031	2%	5%	4%	4%	11%	6%	4%
2032	5%	5%	3%	4%	7%	4%	6%

Table L.8 – Average Loss of Load Probability during Summer Peak

EG1						
Average for operating years 2013 through 2022						
Event Size (MWh)	C03	C07	C11	C15	C16	C17
> 0	92%	92%	92%	91%	92%	92%
> 1,000	75%	75%	75%	71%	75%	74%
> 10,000	25%	25%	25%	21%	24%	25%
> 25,000	8%	8%	9%	8%	9%	9%
> 50,000	1%	1%	1%	1%	1%	1%
> 100,000	0%	0%	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%
Average for operating years 2013 through 2032						
Event Size (MWh)	C03	C07	C11	C15	C16	C17
> 0	91%	92%	90%	90%	90%	93%
> 1,000	74%	78%	72%	69%	73%	78%
> 10,000	23%	28%	22%	18%	23%	29%
> 25,000	8%	10%	8%	7%	8%	11%
> 50,000	1%	3%	2%	1%	2%	4%
> 100,000	0%	1%	0%	0%	0%	1%
> 500,000	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%

EG2							
Average for operating years 2013 through 2022							
Event Size (MWh)	C03	C07	C07a	C11	C15	C16	C17
> 0	92%	92%	92%	92%	92%	92%	92%
> 1,000	75%	75%	75%	75%	74%	75%	74%
> 10,000	24%	24%	24%	25%	24%	25%	25%
> 25,000	8%	9%	9%	8%	8%	9%	8%
> 50,000	1%	1%	1%	1%	1%	1%	1%
> 100,000	0%	0%	0%	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%
Average for operating years 2013 through 2032							
Event Size (MWh)	C03	C07	C07a	C11	C15	C16	C17
> 0	90%	91%	91%	90%	93%	91%	94%
> 1,000	73%	74%	74%	73%	78%	73%	78%
> 10,000	24%	24%	24%	23%	28%	24%	29%
> 25,000	8%	9%	9%	8%	10%	9%	10%
> 50,000	2%	2%	2%	2%	3%	2%	3%
> 100,000	0%	1%	1%	1%	1%	1%	1%
> 500,000	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%

Table L.9 – Core Cases 1 through 19, Portfolio PVRR Cost Components (Zero CO_2 Tax Level)

		Stochastic PVRR ($ millions)											
EG Scenario	Study ID	Thermal Fuel	Variable O&M inlcudes FOT	Emission Cost	Long Term Contracts	Renewables	DSM	System Balancing (System Sales)	System Balancing (System Purchases)	Transmission Wheeling	SBT	Capital and Fixed O&M Cost	Total PVRR
EG1	C01	13,263	1,989	0	1,376	1,273	616	(3,703)	2,165	11	-	10,015	27,004
EG1	C02	12,961	1,988	0	1,375	1,302	645	(3,750)	2,021	11	-	11,031	27,586
EG1	C03	12,939	1,991	0	1,376	1,304	588	(3,734)	2,053	11	-	11,237	27,766
EG1	C04	15,261	2,286	0	1,378	1,272	548	(3,193)	2,665	11	-	9,844	30,071
EG1	C05	14,871	2,226	0	1,378	1,304	559	(3,270)	2,601	11	-	11,075	30,754
EG1	C06	13,390	1,999	0	1,376	1,273	630	(3,808)	2,157	11	-	10,104	27,132
EG1	C07	13,106	1,976	0	1,376	1,303	621	(3,860)	2,100	11	-	11,303	27,935
EG1	C08	15,686	2,395	0	1,378	1,272	482	(3,121)	2,760	10	-	9,947	30,810
EG1	C09	15,280	2,353	0	1,378	1,304	566	(3,202)	2,739	11	-	11,140	31,570
EG1	C10	13,249	1,994	0	1,376	1,272	617	(3,696)	2,133	11	-	10,505	27,461
EG1	C11	12,910	1,974	0	1,376	1,304	656	(3,761)	2,019	11	-	11,701	28,190
EG1	C12	13,381	1,971	0	1,376	1,272	644	(3,804)	2,157	11	-	10,594	27,603
EG1	C13	13,105	1,978	0	1,376	1,304	613	(3,862)	2,111	11	-	11,803	28,439
EG1	C14	14,385	2,120	0	1,377	1,304	979	(3,402)	2,406	11	-	11,023	30,203
EG1	C15	12,599	1,985	0	1,374	1,303	645	(3,451)	2,090	11	-	10,900	27,457
EG1	C16	12,946	1,975	0	1,376	1,347	615	(3,745)	2,050	11	-	11,174	27,748
EG1	C17	13,426	1,757	0	1,377	1,304	751	(4,036)	1,972	11	-	11,623	28,186
EG1	C18	12,994	1,743	0	1,378	1,349	1,278	(3,527)	2,432	11	-	16,327	33,984
EG1	C19												

		Stochastic PVRR ($ millions)											
EG Scenario	Study ID	Thermal Fuel	Variable O&M inlcudes FOT	Emission Cost	Long Term Contracts	Renewables	DSM	System Balancing (System Sales)	System Balancing (System Purchases)	Transmission Wheeling	SBT	Capital and Fixed O&M Cost	Total PVRR
EG2	C01	13,267	2,002	0	1,376	1,273	618	(3,693)	2,085	11	(655)	10,919	27,202
EG2	C02	12,970	1,992	0	1,376	1,306	617	(3,724)	2,005	11	(655)	11,697	27,593
EG2	C03	12,973	1,985	0	1,376	1,312	609	(3,740)	2,042	11	(655)	11,856	27,770
EG2	C04	15,319	2,293	0	1,378	1,272	462	(3,214)	2,564	11	(655)	10,732	30,162
EG2	C05	14,965	2,260	0	1,378	1,313	456	(3,274)	2,481	11	(655)	11,704	30,640
EG2	C06	13,377	1,960	0	1,376	1,272	677	(3,810)	2,139	11	(655)	11,010	27,359
EG2	C07	13,002	1,951	0	1,376	1,313	658	(3,857)	2,014	11	(655)	11,894	27,708
EG2	C07a	13,094	1,961	0	1,376	1,302	661	(3,839)	2,042	11	(654)	11,512	27,466
EG2	C08	15,644	2,319	0	1,378	1,272	568	(3,159)	2,670	11	(655)	10,916	30,965
EG2	C09	15,440	2,275	0	1,377	1,313	560	(3,135)	2,670	10	(655)	11,698	31,554
EG2	C10	13,136	2,013	0	1,376	1,272	670	(3,695)	2,084	11	(655)	11,348	27,559
EG2	C11	12,993	1,958	0	1,375	1,313	606	(3,844)	2,022	11	(655)	12,353	28,132
EG2	C12	13,377	1,960	0	1,376	1,272	677	(3,809)	2,143	11	(655)	11,502	27,855
EG2	C13	13,056	1,957	0	1,376	1,313	693	(3,855)	2,041	11	(655)	12,397	28,333
EG2	C14	14,385	2,105	0	1,377	1,312	992	(3,384)	2,334	11	(655)	11,664	30,142
EG2	C15	12,856	1,899	0	1,377	1,312	626	(3,779)	2,154	11	(655)	11,786	27,588
EG2	C16	13,018	1,950	0	1,376	1,349	615	(3,835)	2,047	11	(655)	11,853	27,729
EG2	C17	13,425	1,757	0	1,377	1,312	763	(4,042)	1,905	11	(655)	12,264	28,118
EG2	C18	12,587	1,753	0	1,377	1,397	1,278	(3,591)	2,257	11	(655)	18,095	34,509
EG2	C19	12,908	1,980	0	1,376	1,313	661	(3,755)	2,009	11	(655)	11,868	27,715

Table L.10 – Core Cases 1 through 19, Portfolio PVRR Cost Components (Medium CO_2 Tax Level)

		Stochastic PVRR ($ millions)											
EG Scenario	Study ID	Thermal Fuel	Variable O&M inlcudes FOT	Emission Cost	Long Term Contracts	Renewables	DSM	System Balancing (System Sales)	System Balancing (System Purchases)	Transmission Wheeling	SBT	Capital and Fixed O&M Cost	Total PVRR
EG1	C01	13,620	2,148	3,236	1,392	1,273	616	(4,071)	2,726	10	-	10,015	30,964
EG1	C02	13,282	2,154	3,137	1,391	1,302	645	(4,123)	2,567	10	-	11,031	31,397
EG1	C03	13,261	2,156	3,125	1,392	1,304	588	(4,109)	2,592	10	-	11,237	31,557
EG1	C04	16,441	2,424	1,883	1,394	1,272	548	(3,506)	3,198	10	-	9,844	33,507
EG1	C05	16,003	2,359	1,834	1,394	1,304	559	(3,609)	3,106	10	-	11,075	34,035
EG1	C06	13,731	2,164	3,297	1,392	1,273	630	(4,178)	2,736	10	-	10,104	31,159
EG1	C07	13,407	2,140	3,192	1,392	1,303	621	(4,237)	2,658	10	-	11,303	31,789
EG1	C08	16,997	2,544	1,843	1,394	1,272	482	(3,418)	3,307	10	-	9,947	34,378
EG1	C09	16,536	2,499	1,807	1,394	1,304	566	(3,521)	3,274	10	-	11,140	35,009
EG1	C10	13,604	2,156	3,237	1,392	1,272	617	(4,062)	2,694	10	-	10,505	31,425
EG1	C11	13,227	2,137	3,111	1,391	1,304	656	(4,134)	2,563	10	-	11,701	31,966
EG1	C12	13,711	2,130	3,302	1,392	1,272	644	(4,174)	2,733	10	-	10,594	31,615
EG1	C13	13,408	2,142	3,192	1,392	1,304	613	(4,240)	2,669	10	-	11,803	32,293
EG1	C14	15,419	2,257	1,935	1,393	1,304	979	(3,778)	2,857	11	-	11,023	33,401
EG1	C15	12,904	2,174	3,135	1,390	1,303	645	(3,795)	2,643	10	-	10,900	31,308
EG1	C16	13,268	2,138	3,131	1,391	1,347	615	(4,116)	2,598	10	-	11,174	31,556
EG1	C17	13,763	1,883	3,258	1,394	1,304	751	(4,442)	2,491	10	-	11,623	32,036
EG1	C18	13,594	1,869	2,579	1,394	1,349	1,278	(3,943)	2,932	10	-	16,327	37,390
EG1	C19												

		Stochastic PVRR ($ millions)											
EG Scenario	Study ID	Thermal Fuel	Variable O&M inlcudes FOT	Emission Cost	Long Term Contracts	Renewables	DSM	System Balancing (System Sales)	System Balancing (System Purchases)	Transmission Wheeling	SBT	Capital and Fixed O&M Cost	Total PVRR
EG2	C01	13,652	2,166	3,214	1,392	1,273	618	(4,072)	2,621	10	(655)	10,919	31,138
EG2	C02	13,316	2,162	3,142	1,392	1,306	617	(4,102)	2,548	10	(655)	11,697	31,432
EG2	C03	13,313	2,149	3,132	1,392	1,312	609	(4,116)	2,592	10	(655)	11,856	31,596
EG2	C04	16,509	2,435	1,870	1,394	1,272	462	(3,540)	3,064	10	(655)	10,732	33,554
EG2	C05	16,123	2,398	1,821	1,394	1,313	456	(3,621)	2,955	10	(655)	11,704	33,898
EG2	C06	13,704	2,118	3,311	1,392	1,272	677	(4,182)	2,718	10	(655)	11,010	31,376
EG2	C07	13,289	2,114	3,196	1,392	1,313	658	(4,236)	2,581	10	(655)	11,894	31,556
EG2	C07a	13,387	2,125	3,226	1,392	1,302	661	(4,216)	2,612	10	(654)	11,512	31,357
EG2	C08	16,934	2,454	1,906	1,394	1,273	568	(3,467)	3,215	10	(655)	10,916	34,548
EG2	C09	16,720	2,406	1,733	1,393	1,313	560	(3,436)	3,202	10	(655)	11,698	34,944
EG2	C10	13,468	2,185	3,238	1,391	1,272	670	(4,066)	2,639	10	(655)	11,348	31,501
EG2	C11	13,269	2,118	3,209	1,391	1,313	606	(4,218)	2,590	10	(655)	12,353	31,986
EG2	C12	13,704	2,117	3,312	1,392	1,272	677	(4,183)	2,724	10	(655)	11,502	31,874
EG2	C13	13,351	2,120	3,208	1,391	1,313	693	(4,234)	2,608	10	(655)	12,397	32,202
EG2	C14	15,408	2,237	1,965	1,393	1,312	992	(3,745)	2,803	11	(655)	11,664	33,384
EG2	C15	13,118	2,079	3,243	1,392	1,312	626	(4,152)	2,720	10	(655)	11,786	31,480
EG2	C16	13,290	2,108	3,237	1,391	1,350	615	(4,208)	2,617	10	(655)	11,853	31,607
EG2	C17	13,767	1,881	3,267	1,394	1,312	763	(4,452)	2,434	10	(655)	12,264	31,985
EG2	C18	13,104	1,892	2,577	1,394	1,397	1,278	(4,012)	2,755	10	(655)	18,095	37,836
EG2	C19	13,228	2,145	3,132	1,391	1,313	661	(4,128)	2,564	10	(655)	11,868	31,528

Table L.11 – Core Cases 1 through 19, Portfolio PVRR Cost Components (High CO2 Tax Level)

		Stochastic PVRR ($ millions)											
EG Scenario	Study ID	Thermal Fuel	Variable O&M inlcudes FOT	Emission Cost	Long Term Contracts	Renewables	DSM	System Balancing (System Sales)	System Balancing (System Purchases)	Transmission Wheeling	SBT	Capital and Fixed O&M Cost	Total PVRR
EG1	C01	14,471	2,449	8,255	1,405	1,273	616	(4,698)	3,541	10	-	10,015	37,337
EG1	C02	14,075	2,466	7,992	1,404	1,302	645	(4,758)	3,365	10	-	11,031	37,534
EG1	C03	14,055	2,470	7,964	1,405	1,304	588	(4,746)	3,382	10	-	11,237	37,668
EG1	C04	18,264	2,686	5,045	1,407	1,273	548	(4,127)	3,911	10	-	9,844	38,860
EG1	C05	17,758	2,616	4,921	1,407	1,304	559	(4,267)	3,772	10	-	11,075	39,155
EG1	C06	14,577	2,461	8,414	1,405	1,273	630	(4,843)	3,561	10	-	10,104	37,593
EG1	C07	14,203	2,436	8,120	1,405	1,303	621	(4,913)	3,466	10	-	11,303	37,953
EG1	C08	18,824	2,818	4,873	1,407	1,273	482	(4,032)	4,012	9	-	9,947	39,613
EG1	C09	18,277	2,767	4,794	1,407	1,304	566	(4,176)	3,958	10	-	11,140	40,046
EG1	C10	14,453	2,461	8,264	1,405	1,273	617	(4,690)	3,505	10	-	10,505	37,803
EG1	C11	14,021	2,444	7,907	1,404	1,304	656	(4,775)	3,355	10	-	11,701	38,027
EG1	C12	14,547	2,421	8,431	1,405	1,273	644	(4,838)	3,560	10	-	10,594	38,046
EG1	C13	14,201	2,439	8,121	1,405	1,304	613	(4,914)	3,478	10	-	11,803	38,460
EG1	C14	17,117	2,522	5,130	1,406	1,304	979	(4,489)	3,459	10	-	11,023	38,461
EG1	C15	13,708	2,518	7,969	1,403	1,303	645	(4,420)	3,447	10	-	10,900	37,483
EG1	C16	14,061	2,448	7,970	1,404	1,347	615	(4,752)	3,400	10	-	11,174	37,677
EG1	C17	14,614	2,122	8,316	1,407	1,304	751	(5,175)	3,212	10	-	11,623	38,184
EG1	C18	14,844	2,128	6,561	1,407	1,349	1,278	(4,695)	3,565	10	-	16,327	42,774
EG1	C19												

		Stochastic PVRR ($ millions)											
EG Scenario	Study ID	Thermal Fuel	Variable O&M inlcudes FOT	Emission Cost	Long Term Contracts	Renewables	DSM	System Balancing (System Sales)	System Balancing (System Purchases)	Transmission Wheeling	SBT	Capital and Fixed O&M Cost	Total PVRR
EG2	C01	14,520	2,476	8,219	1,405	1,273	618	(4,714)	3,397	10	(655)	10,919	37,468
EG2	C02	14,149	2,482	7,976	1,405	1,306	617	(4,747)	3,332	10	(655)	11,697	37,571
EG2	C03	14,122	2,458	7,963	1,405	1,312	609	(4,755)	3,397	10	(655)	11,856	37,722
EG2	C04	18,354	2,702	5,014	1,407	1,273	462	(4,176)	3,736	10	(655)	10,732	38,858
EG2	C05	17,905	2,657	4,876	1,407	1,313	456	(4,289)	3,585	10	(655)	11,704	38,968
EG2	C06	14,531	2,406	8,463	1,405	1,273	677	(4,853)	3,549	10	(655)	11,010	37,816
EG2	C07	14,045	2,407	8,125	1,405	1,313	658	(4,917)	3,392	10	(655)	11,894	37,677
EG2	C07a	14,150	2,419	8,212	1,405	1,302	661	(4,893)	3,422	10	(654)	11,512	37,546
EG2	C08	18,744	2,710	5,026	1,407	1,273	568	(4,095)	3,919	10	(655)	10,916	39,822
EG2	C09	18,503	2,638	4,588	1,406	1,313	560	(4,063)	3,881	9	(655)	11,698	39,877
EG2	C10	14,278	2,510	8,267	1,404	1,273	670	(4,701)	3,445	10	(655)	11,348	37,849
EG2	C11	14,014	2,422	8,162	1,404	1,313	606	(4,892)	3,408	10	(655)	12,353	38,146
EG2	C12	14,532	2,406	8,464	1,405	1,273	677	(4,853)	3,553	10	(655)	11,502	38,315
EG2	C13	14,122	2,415	8,157	1,404	1,313	693	(4,913)	3,430	10	(655)	12,397	38,373
EG2	C14	17,098	2,494	5,194	1,406	1,312	992	(4,435)	3,439	10	(655)	11,664	38,520
EG2	C15	13,860	2,417	8,233	1,406	1,312	626	(4,815)	3,536	10	(655)	11,786	37,716
EG2	C16	14,018	2,408	8,264	1,405	1,350	615	(4,881)	3,432	10	(655)	11,853	37,817
EG2	C17	14,622	2,116	8,321	1,407	1,312	763	(5,193)	3,165	10	(655)	12,264	38,132
EG2	C18	14,221	2,165	6,516	1,407	1,398	1,278	(4,765)	3,388	10	(655)	18,095	43,058
EG2	C19	14,007	2,456	7,963	1,404	1,313	661	(4,766)	3,369	10	(655)	11,868	37,630

APPENDIX M – CASE STUDY FACT SHEETS

Introduction

This appendix documents the 2013 Integrated Resource Plan modeling assumptions used for the Core Case studies and the Sensitivity Case studies in a 2-page format handout given to participants to identify key assumptions used. These aided in the discussion during the public process and gave details beyond the high level summary tables. The Core Case Fact sheets were provided to the public on December 19, 2012 and the Sensitivity Case Fact Sheets were provided on February 27, 2013.

Case Fact Sheets Summary Tables

Table M.1 – Core Case Definitions

Theme	Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Other
Reference	C01	Medium	Medium	Medium	None	Base	n/a
	C02	Medium	Medium	Medium	State	Base	n/a
	C03	Medium	Medium	Medium	State & Federal	Base	n/a
Environmental	C04	Low	High	High	None	Base	n/a
Policy	C05	Low	High	High	State & Federal	Base	n/a
	C06	High	Zero	Low	None	Base	n/a
	C07	High	Zero	Low	State & Federal	Base	n/a
	C08	Low	High	High	None	Base	n/a
	C09	Low	High	High	State & Federal	Base	n/a
	C10	Medium	Medium	Medium	None	Base	n/a
	C11	Medium	Medium	Medium	State & Federal	Base	n/a
	C12	High	Zero	Low	None	Base	n/a
	C13	High	Zero	Low	State & Federal	Base	n/a
	C14	Medium	Hard Cap (Medium Gas)	Medium	State & Federal	Accelerated	n/a
Targeted	C15	Medium	Medium	Medium	State & Federal	Accelerated	No CCCT
Resources	C16	Medium	Medium	Medium	State & Federal	Base	Geothermal/RPS
	C17	High	Medium	Medium	State & Federal	Base	Market Spike
	C18	Medium	Hard Cap (High Gas)	Medium	None	Accelerated	Clean Energy
Transmission	C19	Medium	Medium	Medium	State & Federal	Base	Alt. to Segment D

Table M.2 – Sensitivity Case Definitions

Theme	Case #	Load	Gas Price	CO2 Price	RPS	PTC/ITC	Coal Investments
Load Sensitivity	S-01	Low	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-02	High	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
	S-03	1 in 20	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Targeted Resource	S-05	Base	Medium	Medium	None	2019/2019	Optimized
	S-06	Base	Medium	Medium	State & Federal (RPS Floor)	2019/2019	Optimized
	S-07	Base	Medium	Medium	State & Federal (Optimized)	2012/2016	Optimized
	S-09	Base	High	High	State & Federal (RPS Floor)	2019/2019	Optimized
	S-10	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Optimized
Environmental Policy	S-04 (Volume 3)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Hypothetical Regional Haze
	S-X (Volume 3)	Base	Medium	Medium	State & Federal (RPS Floor)	2012/2016	Next Best Alternative

Notes

1. All sensitivity cases are based on Energy Gateway Scenario 2, consistent with the scenario in the 2013 IRP preferred portfolio.
2. Sensitivity Case S-07 applies state RPS targets as system targets in the System Optimizer model. All other sensitivities either use the RPS Scenario Maker to establish a renewable resource floor or exclude RPS requirements altogether.
3. Case S-08 (simulating PacifiCorp's 2013 Business Plan portfolio in the current input setup) was removed due to incompatibilities in how Class 2 DSM resources are modeled in the 2013 IRP.
4. Sensitivity cases S-04 (Hypothetical Regional Haze Compliance Alternative) and S-X (Emission Control PVRR(d) Analysis) are confidential and summarized in confidential Volume III of the 2013 IRP report.

Sensitivity cases S-04 (Hypothetical Regional Haze Compliance Alternative) and S-X (Emission Control PVRR(d) Analysis) are confidential and summarized in confidential Volume III to this report.

Core Case Fact Sheets

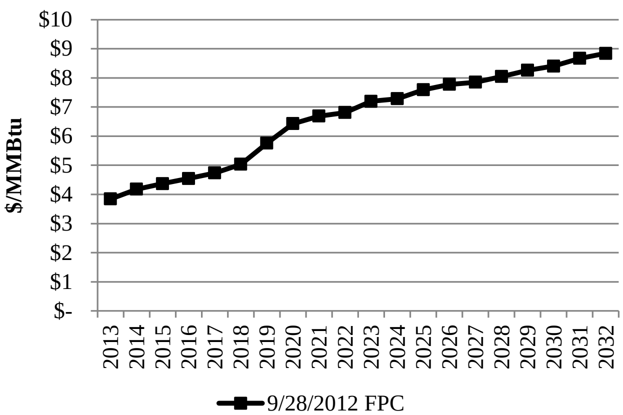
Core Case Fact Sheets – C-01 to C-19

Theme: Reference
Case: C-1 (Base, No RPS)

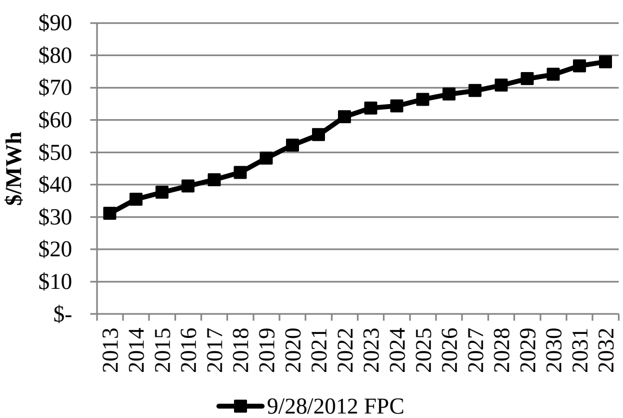
Description
Case C-1 is one of three core cases in the "Reference" theme (Cases C-1 through C-3). These cases are characterized by base/medium assumptions and varying degrees of RPS assumptions. This structure will enable reporting on how RPS requirements, whether state or federal, influence resource portfolios, costs and stochastic risk.

Forward Price Curve
Case C-1 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices

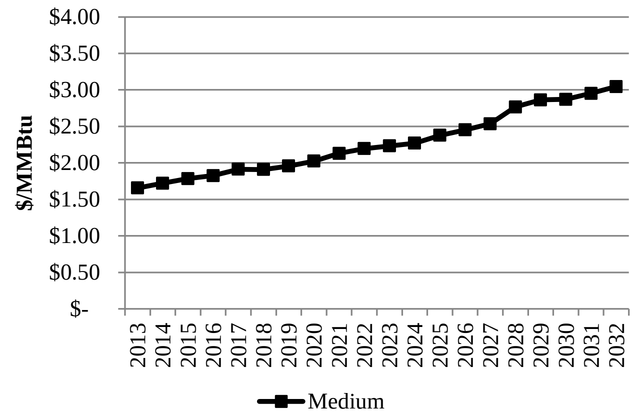


Nominal Average Annual Power Prices (Flat)



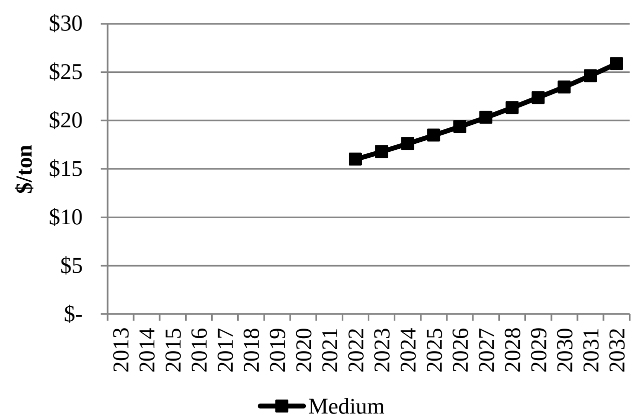
Coal Fuel Costs
Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal
Case C-1 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze
Case C-1 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-1 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-1 does not include any federal RPS requirements.

State RPS

Case C-1 does not include any state RPS requirements.

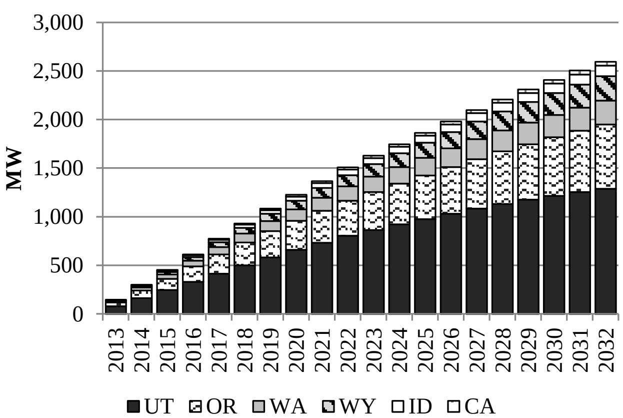
Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.

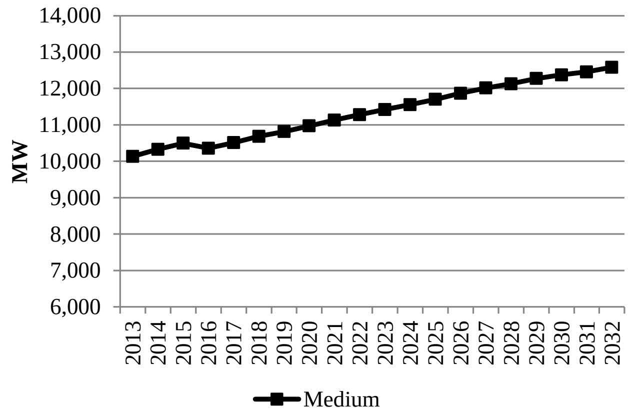
Class 2 DSM Cumulative Achievable Potential



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.

Coincident System Peak Load



Resource Specific

There are no other specific resource constraints that will be applied to this case.

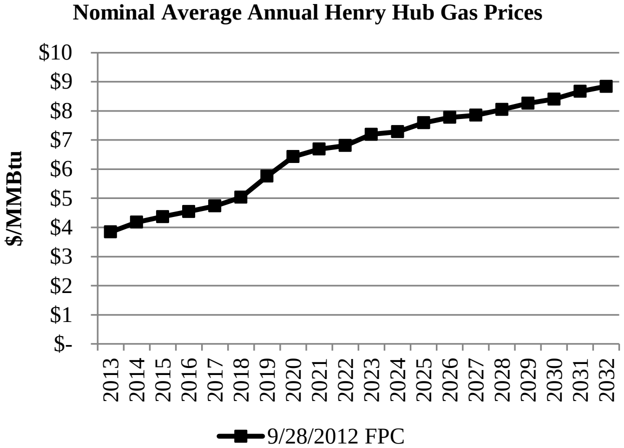
Theme: Reference
Case: C-2 (Base, State RPS)

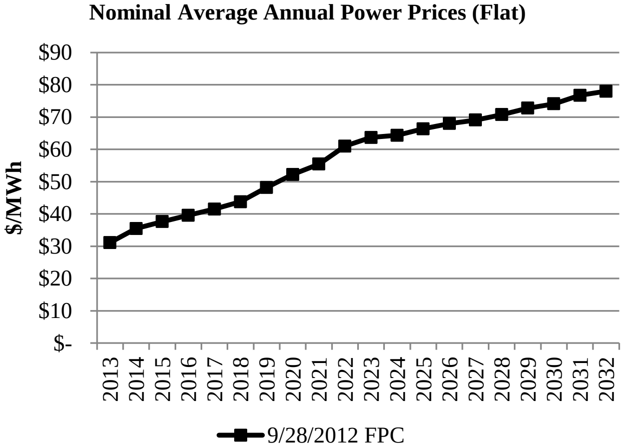
Description

Case C-2 is one of three core cases in the "Reference" theme (Cases C-1 through C-3). These cases are characterized by base/medium assumptions and varying degrees of RPS assumptions. This structure will enable reporting on how RPS requirements, whether state or federal, influence resource portfolios, costs and stochastic risk.

Forward Price Curve

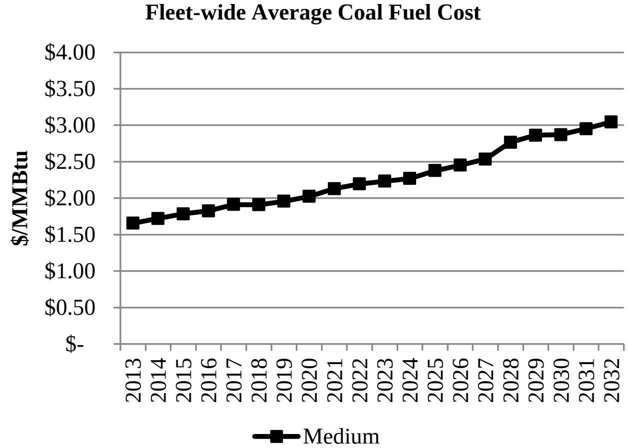
Case C-2 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





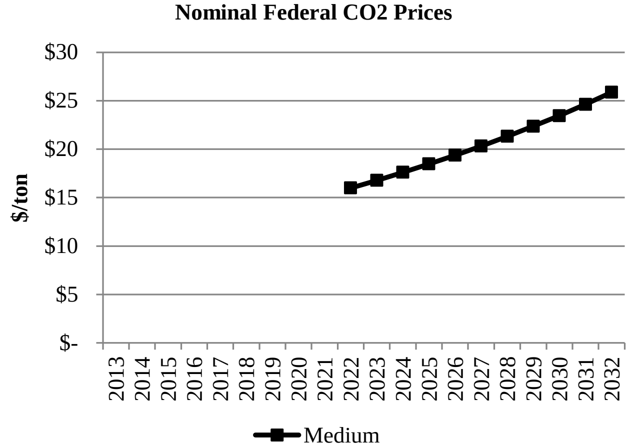
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Case C-2 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Case C-2 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Reference
Case: C-2 (Base, State RPS)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-2 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-2 does not include any federal RPS requirements.

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

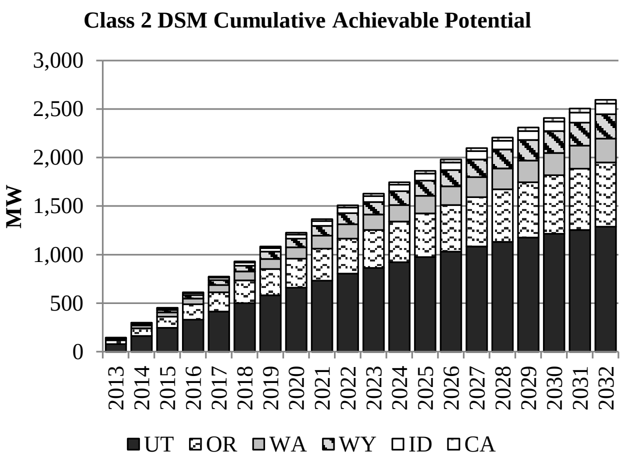
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

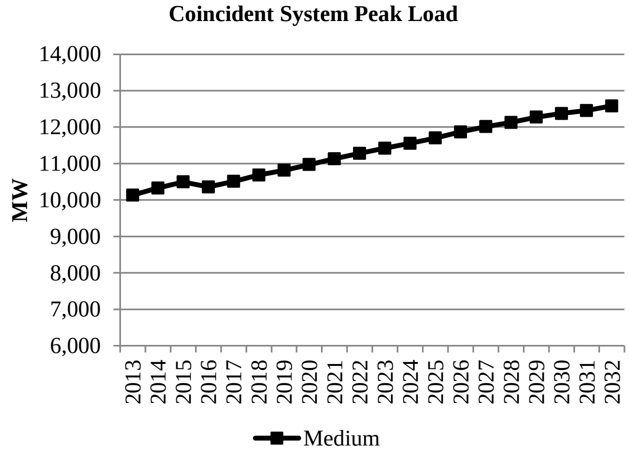
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

Theme: Reference
Case: C-3 (Base, State & Federal RPS)

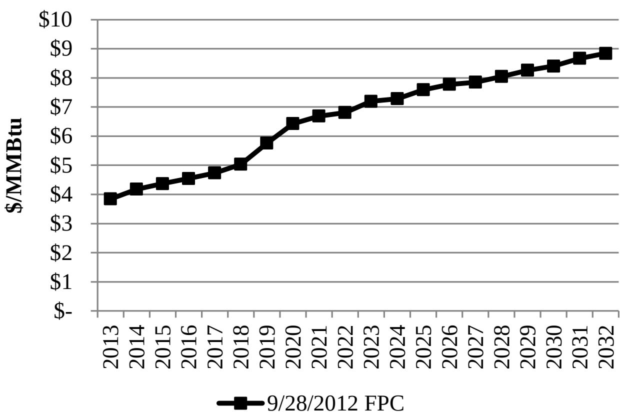
Description

Case C-3 is one of three core cases in the "Reference" theme (Cases C-1 through C-3). These cases are characterized by base/medium assumptions and varying degrees of RPS assumptions. This structure will enable reporting on how RPS requirements, whether state or federal, influence resource portfolios, costs and stochastic risk.

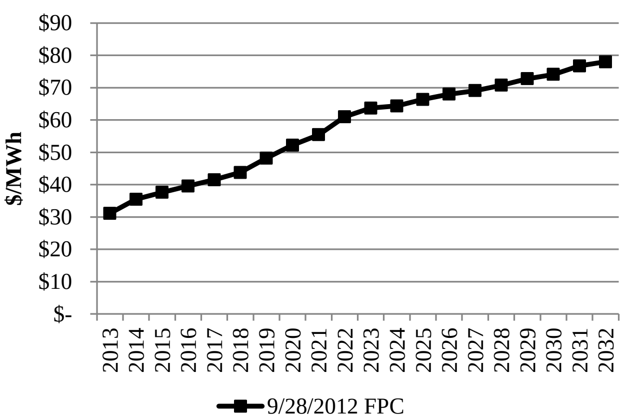
Forward Price Curve

Case C-3 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices



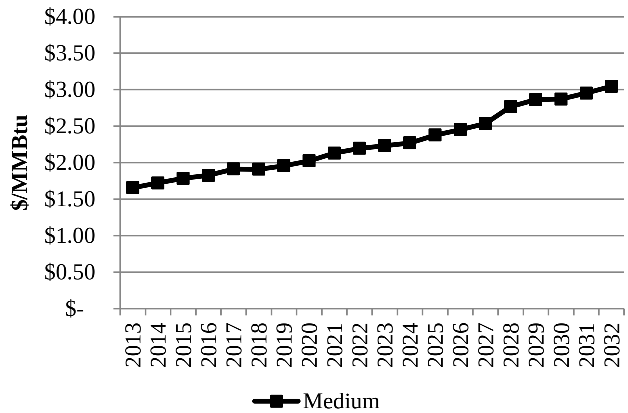
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

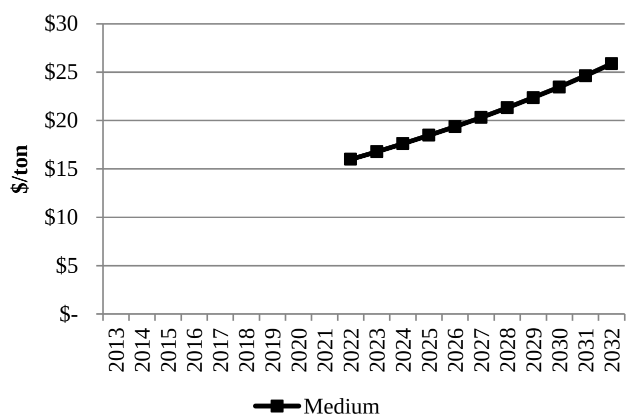
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-3 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze

Case C-3 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Reference
Case: C-3 (Base, State & Federal RPS)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-3 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-3 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

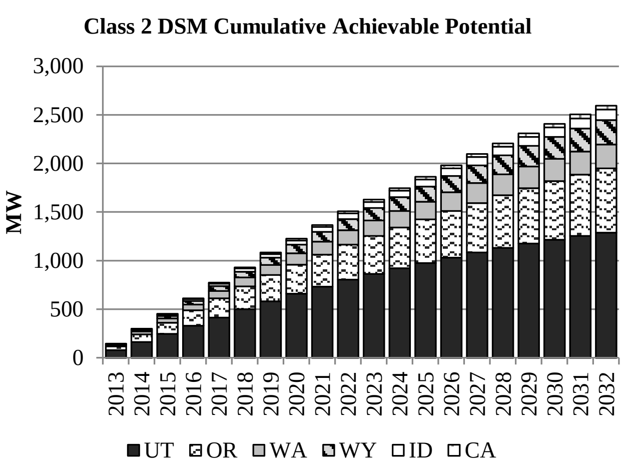
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

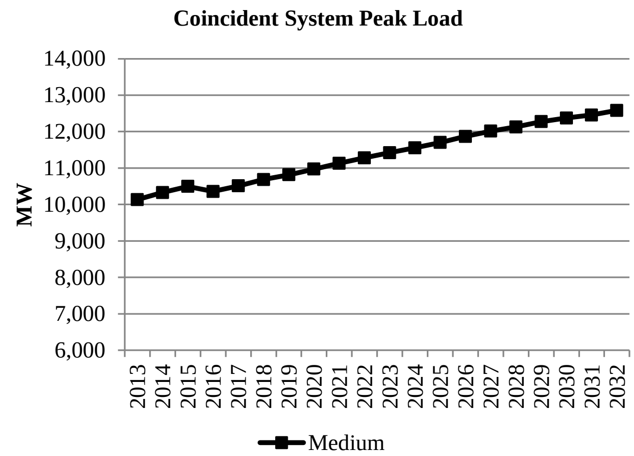
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

Theme: Environmental Policy
Case: C-4 (Base Regional Haze, Low Gas, High CO_2 & Coal, No RPS)

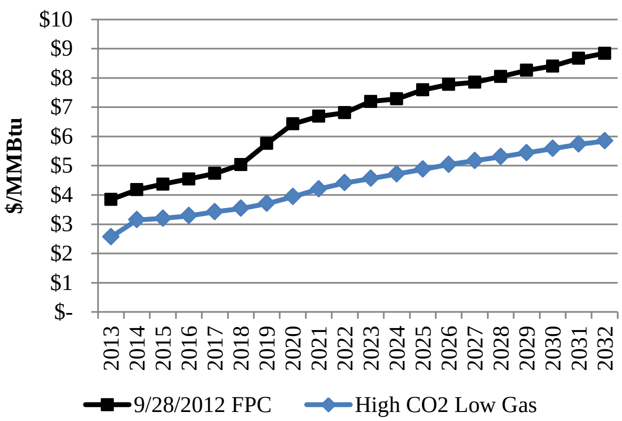
Description

Case C-4 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

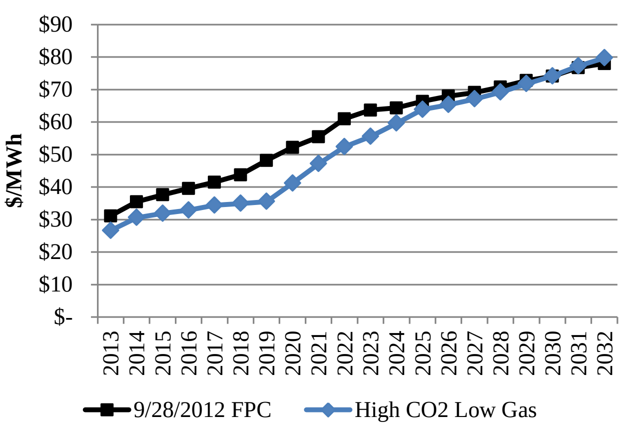
Forward Price Curve

Case C-4 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



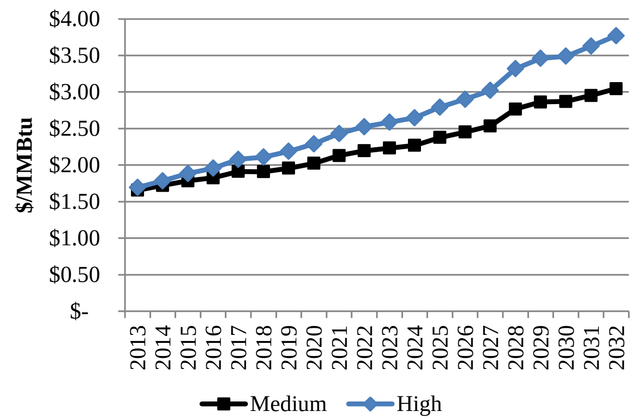
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Case C-4 high coal costs are shown alongside the medium coal costs in the figure below.

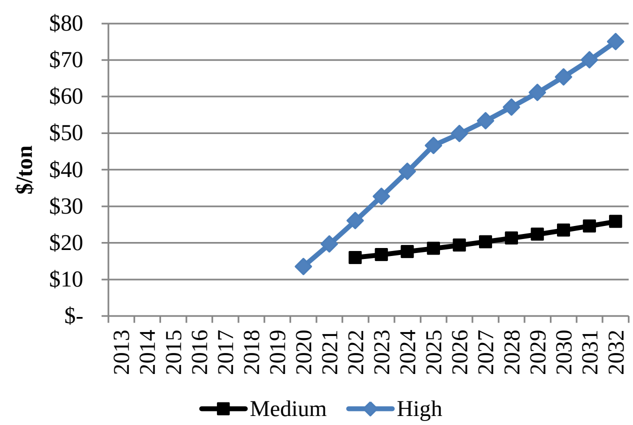
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-4 includes high CO_2 prices starting 2020 at approximately $14/ton rising to approximately $75/ton by 2032. These high CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.

Nominal Federal CO2 Prices



Regional Haze

Case C-4 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016

Theme: Environmental Policy
Case: C-4 (Base Regional Haze, Low Gas, High CO_2 & Coal, No RPS)

Coal Unit	State	Technology*	Year
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions
Case C-4 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

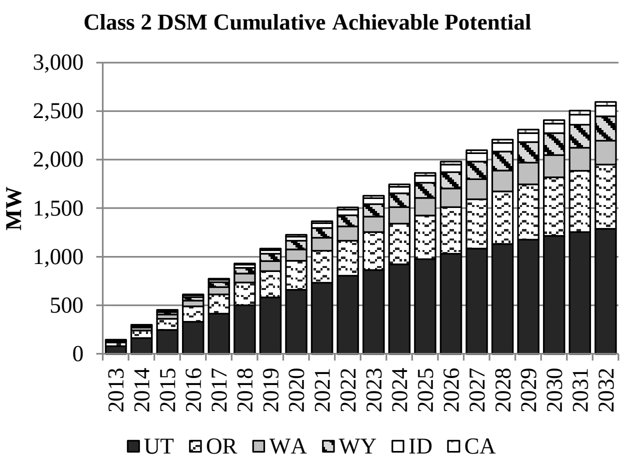
Federal RPS
Case C-4 does not include any federal RPS requirements.

State RPS
Case C-4 does not include any state RPS requirements.

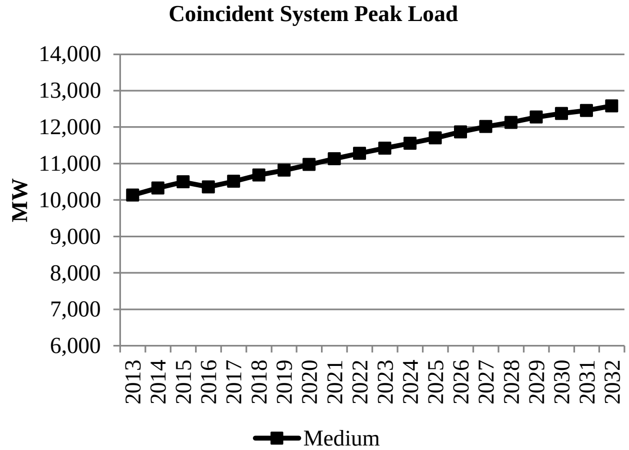
Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific
There are no other specific resource constraints that will be applied to this case.

Theme: Environmental Policy
Case: C-5 (Base Regional Haze, Low Gas, High CO_2 & Coal, With RPS)

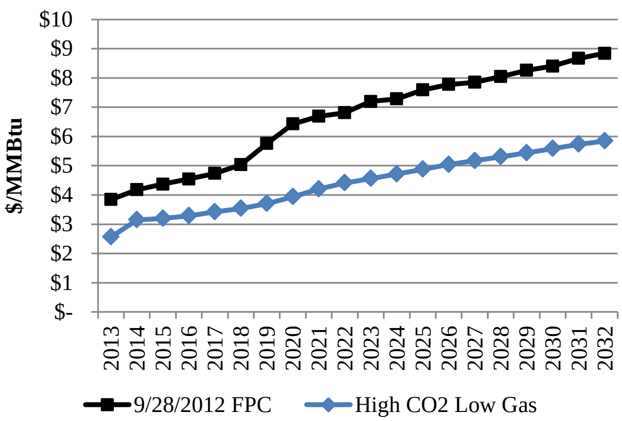
Description

Case C-5 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

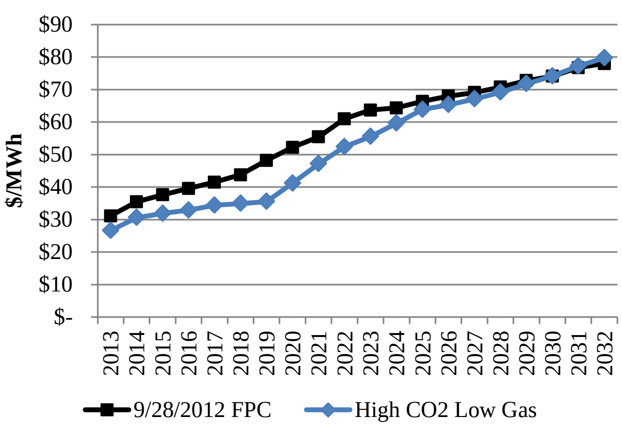
Forward Price Curve

Case C-5 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



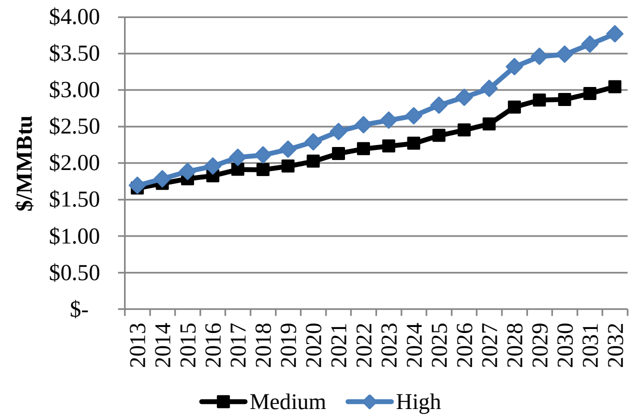
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Case C-5 high coal costs are shown alongside the medium coal costs in the figure below.

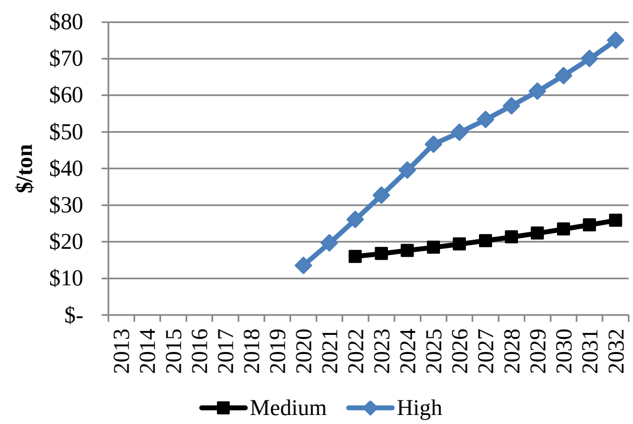
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-5 includes high CO_2 prices starting 2020 at approximately $14/ton rising to approximately $75/ton by 2032. These high CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.

Nominal Federal CO2 Prices



Regional Haze

Case C-5 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016

Theme: Environmental Policy
Case: C-5 (Base Regional Haze, Low Gas, High CO_2 & Coal, With RPS)

Coal Unit	State	Technology*	Year
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-5 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-5 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

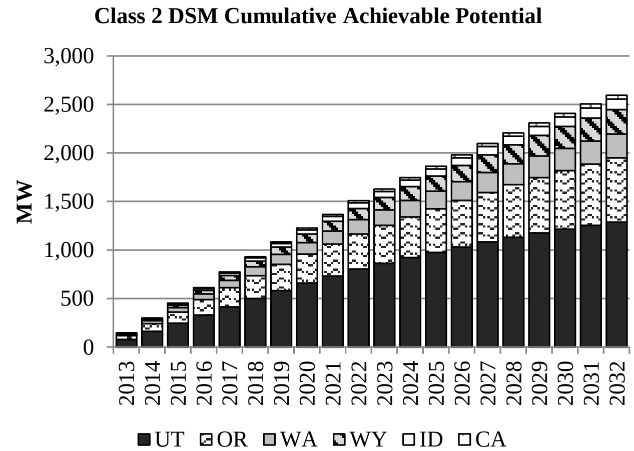
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

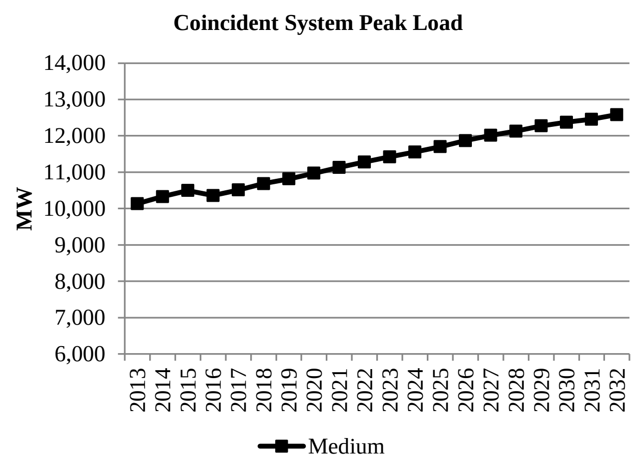
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

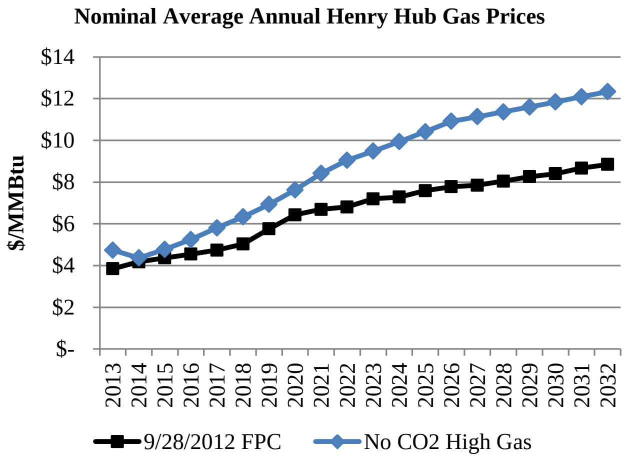
Theme: Environmental Policy
Case: C-6 (Base Regional Haze, High Gas, No CO_2, Low Coal, No RPS)

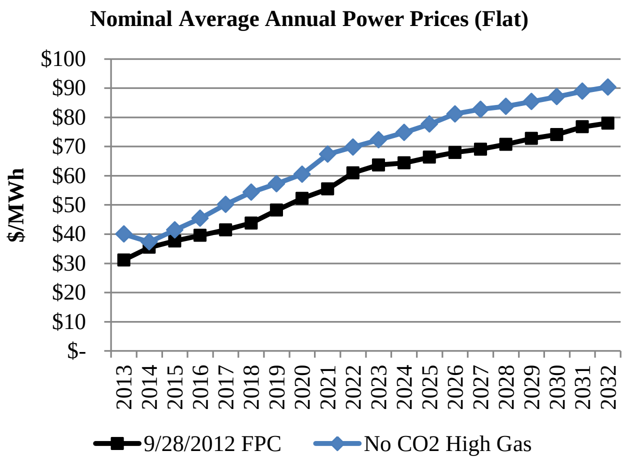
Description

Case C-6 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

Forward Price Curve

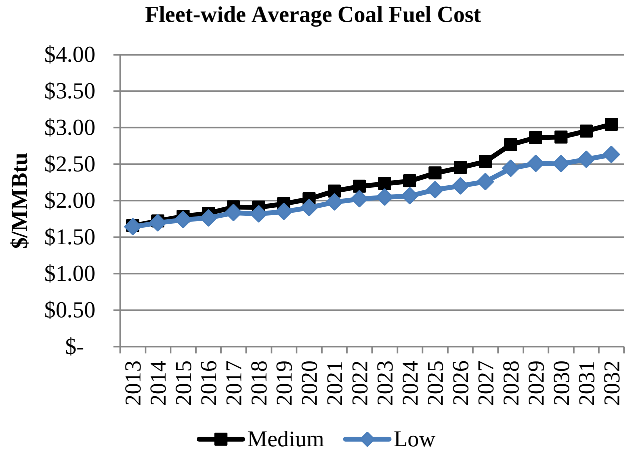
Case C-6 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.





Coal Fuel Costs

Case C-6 low coal costs are shown alongside the medium coal costs in the figure below.



Federal CO_2 Policy/Price Signal

Case C-6 does not have a federal CO_2 price assumption.

Regional Haze

Case C-6 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-6 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-6 does not include any federal RPS requirements.

Theme: Environmental Policy
Case: C-6 (Base Regional Haze, High Gas, No CO_2, Low Coal, No RPS)

State RPS

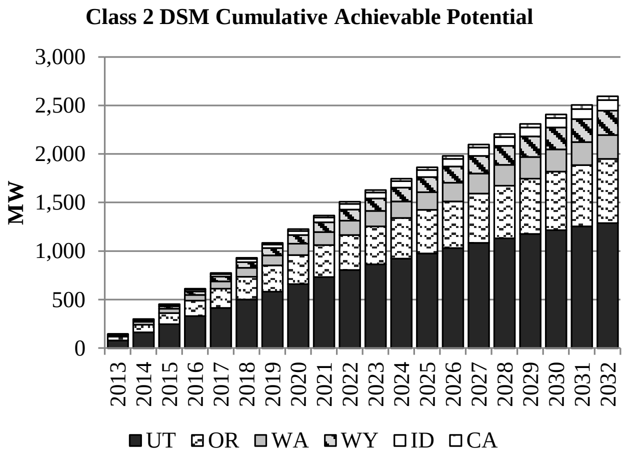
Case C-6 does not include any state RPS requirements.

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

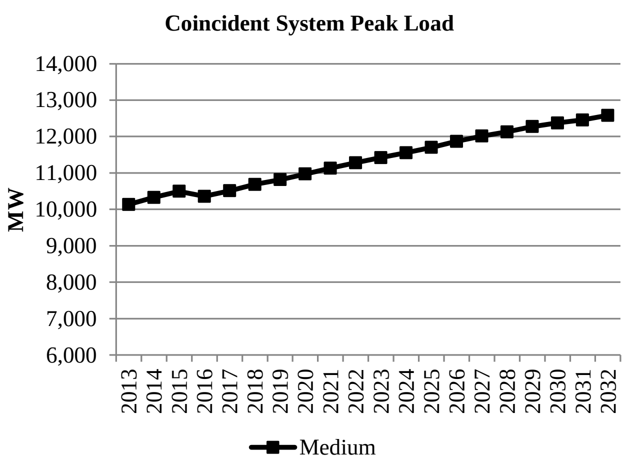
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

Theme: Environmental Policy
Case: C-7 (Base Regional Haze, High Gas, No CO_2, Low Coal, With RPS)

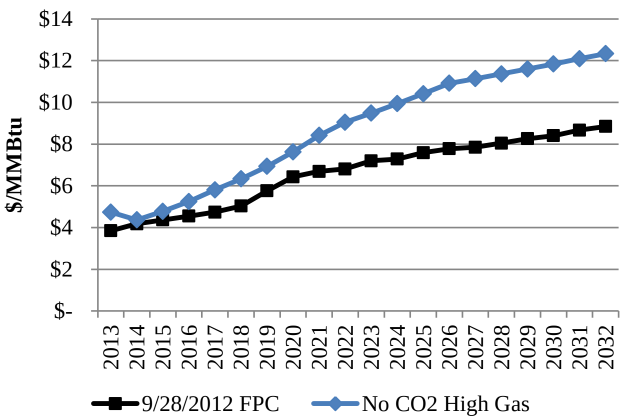
Description

Case C-7 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

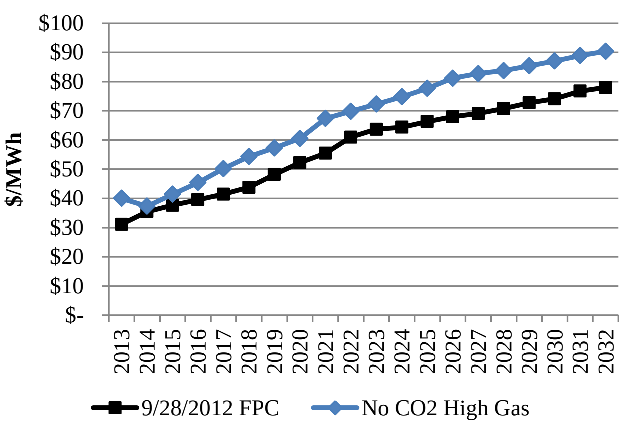
Forward Price Curve

Case C-7 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



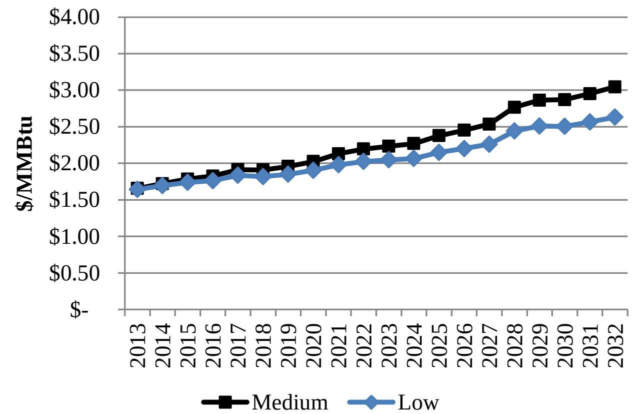
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Case C-7 low coal costs are shown alongside the medium coal costs in the figure below.

Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-7 does not have a federal CO_2 price assumption.

Regional Haze

Case C-7 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-7 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-7 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)

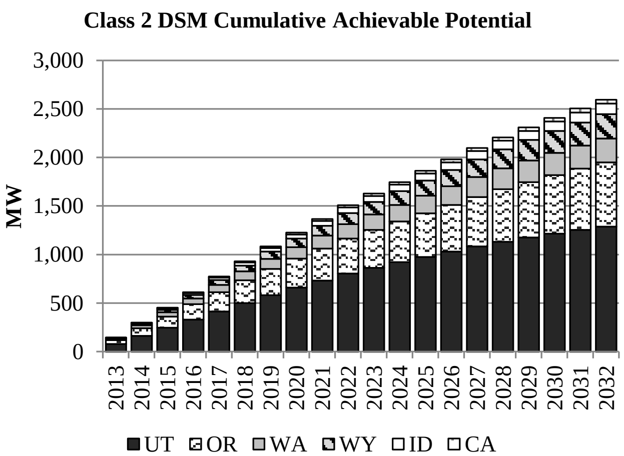
Theme: Environmental Policy
Case: C-7 (Base Regional Haze, High Gas, No CO_2, Low Coal, With RPS)

- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

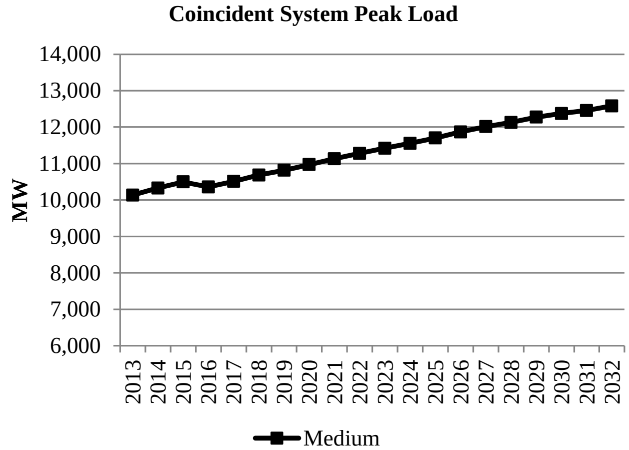
State RPS
Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives
- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.

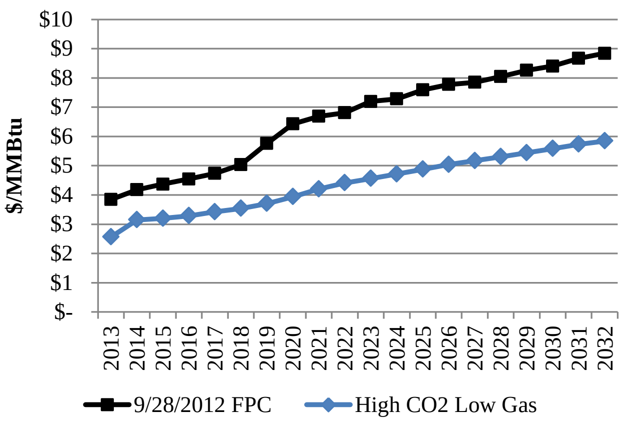


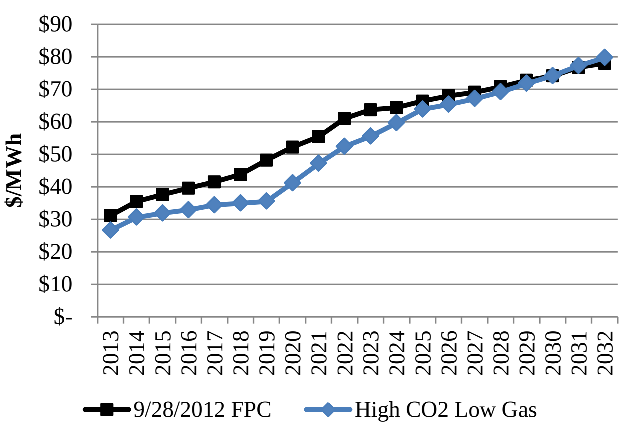
Resource Specific
There are no other specific resource constraints that will be applied to this case.

Theme: Environmental Policy
Case: C-8 (Stringent Regional Haze, Low Gas, High CO_2 & Coal, No RPS)

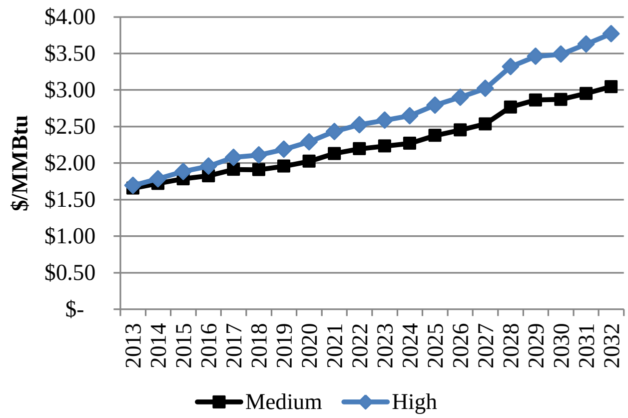
Description
Case C-8 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

Forward Price Curve
Case C-8 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

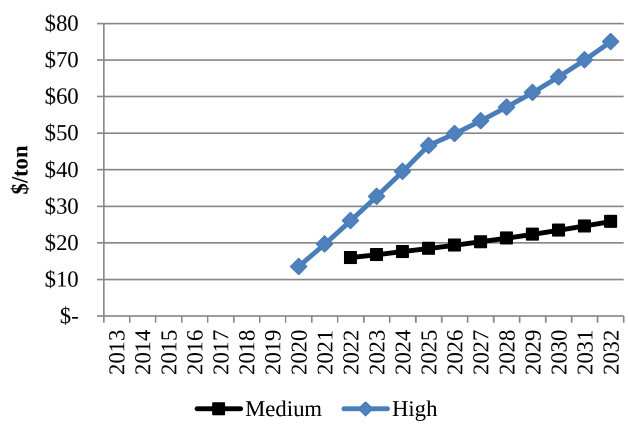




Coal Fuel Costs
Case C-8 high coal costs are shown alongside the medium coal costs in the figure below.



Federal CO_2 Policy/Price Signal
Case C-8 includes high CO_2 prices starting 2020 at approximately $14/ton rising to approximately $75/ton by 2032. These high CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.



Regional Haze
Case C-8 will apply stringent case Regional Haze investments patterned after prospective federal implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
DJ 1	WY	LNB	2016
DJ 2	WY	LNB	2018
DJ 3	WY	SNCR	2017
J. Bridger 1	WY	SCR	2017
J. Bridger 2	WY	SCR	2017
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Wyodak	WY	SNCR	2017
Wyodak	WY	SCR	2025
Hunter 1	UT	BH, LNB	2014
Hunter 1	UT	SCR	2018

Theme: Environmental Policy
Case: C-8 (Stringent Regional Haze, Low Gas, High CO_2 & Coal, No RPS)

Coal Unit	State	Technology*	Year
Hunter 2	UT	SCR	2017
Hunter 3	UT	SCR	2020
Huntington 1	UT	SCR	2018
Huntington 2	UT	SCR	2017
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 1	CO	SCR	2024
Craig 2	CO	SCR	2016
Colstrip 3	MT	SCR	2023
Colstrip 4	MT	SCR	2024
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-8 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-8 does not include any federal RPS requirements.

State RPS

Case C-8 does not include any state RPS requirements.

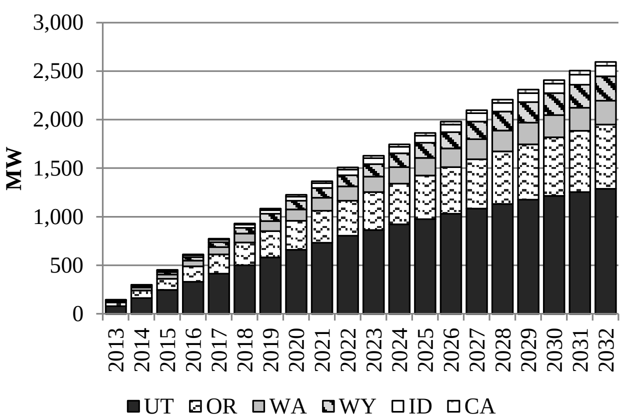
Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.

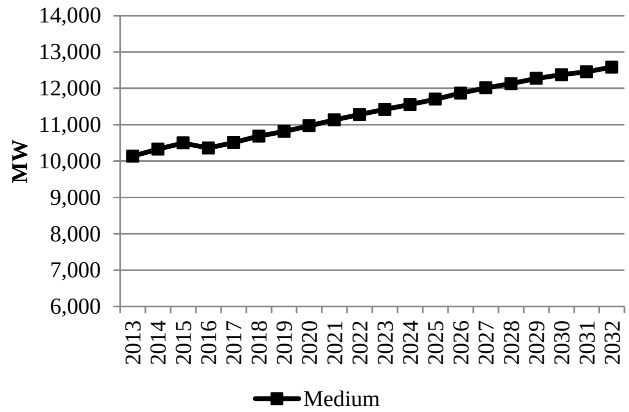
Class 2 DSM Cumulative Achievable Potential



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.

Coincident System Peak Load



Resource Specific

There are no other specific resource constraints that will be applied to this case.

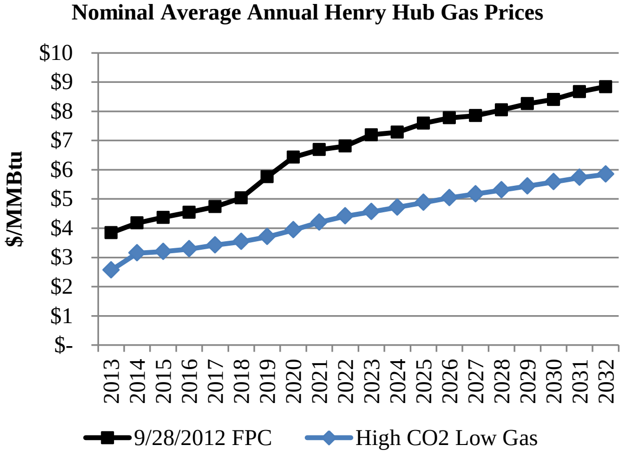
Theme: Environmental Policy
Case: C-9 (Stringent Regional Haze, Low Gas, High CO_2 & Coal, With RPS)

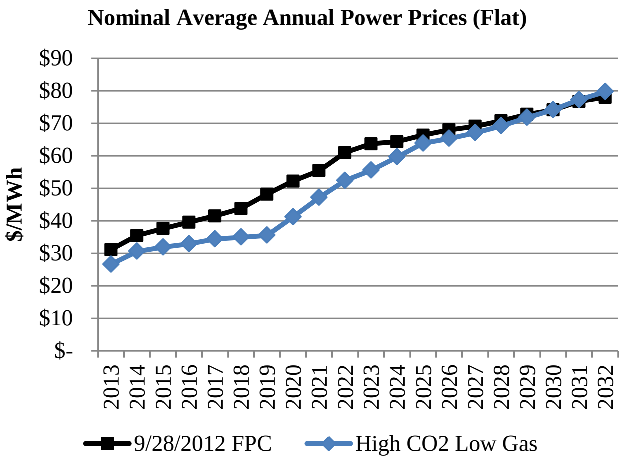
Description

Case C-9 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

Forward Price Curve

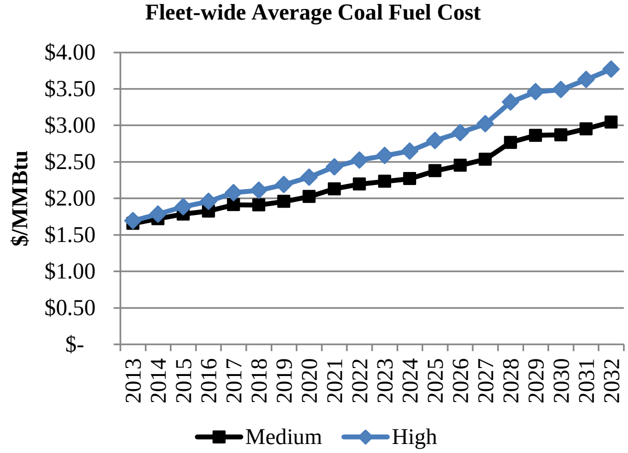
Case C-9 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.





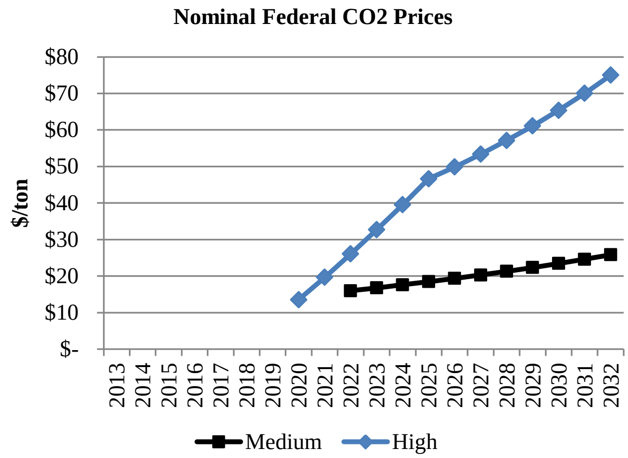
Coal Fuel Costs

Case C-9 high coal costs are shown alongside the medium coal costs in the figure below.



Federal CO_2 Policy/Price Signal

Case C-9 includes high CO_2 prices starting 2020 at approximately $14/ton rising to approximately $75/ton by 2032. These high CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.



Regional Haze

Case C-9 will apply stringent case Regional Haze investments patterned after prospective federal implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
DJ 1	WY	LNB	2016
DJ 2	WY	LNB	2018
DJ 3	WY	SNCR	2017
J. Bridger 1	WY	SCR	2017
J. Bridger 2	WY	SCR	2017
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Wyodak	WY	SNCR	2017
Wyodak	WY	SCR	2025
Hunter 1	UT	BH, LNB	2014
Hunter 1	UT	SCR	2018

Theme: Environmental Policy
Case: C-9 (Stringent Regional Haze, Low Gas, High CO_2 & Coal, With RPS)

Coal Unit	State	Technology*	Year
Hunter 2	UT	SCR	2017
Hunter 3	UT	SCR	2020
Huntington 1	UT	SCR	2018
Huntington 2	UT	SCR	2017
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 1	CO	SCR	2024
Craig 2	CO	SCR	2016
Colstrip 3	MT	SCR	2023
Colstrip 4	MT	SCR	2024
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-9 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-9 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

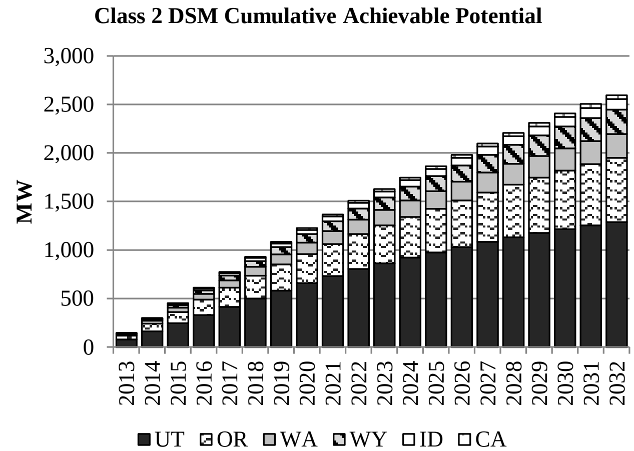
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

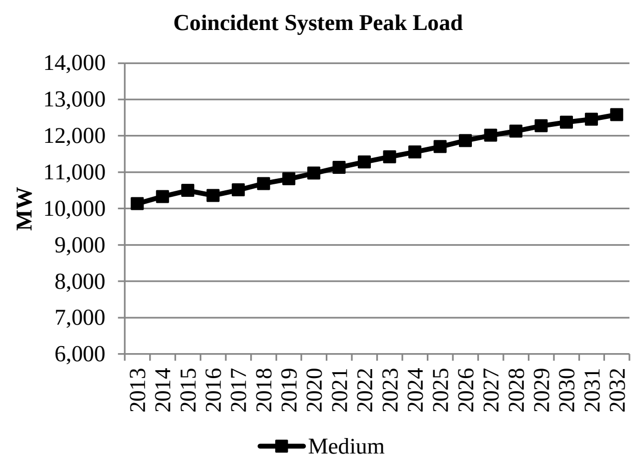
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

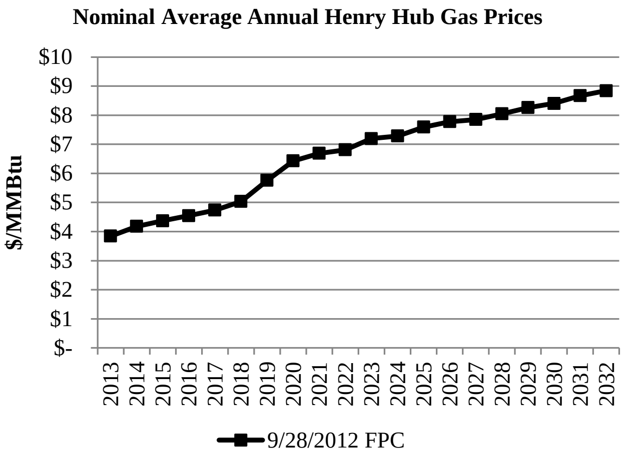
Theme: Environmental Policy
Case: C-10 (Stringent Regional Haze, Med Gas, Med CO_2 & Coal, No RPS)

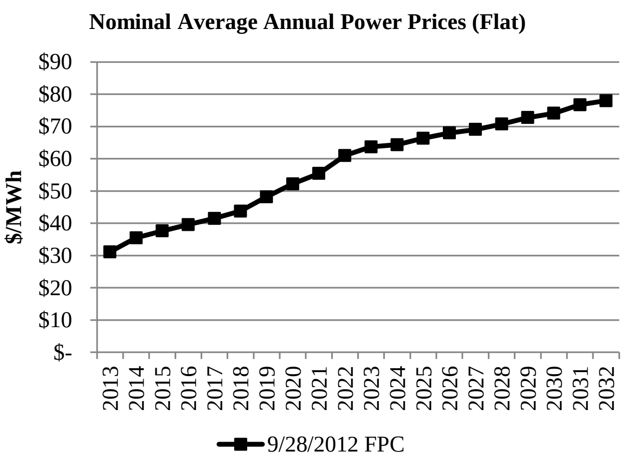
Description

Case C-10 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

Forward Price Curve

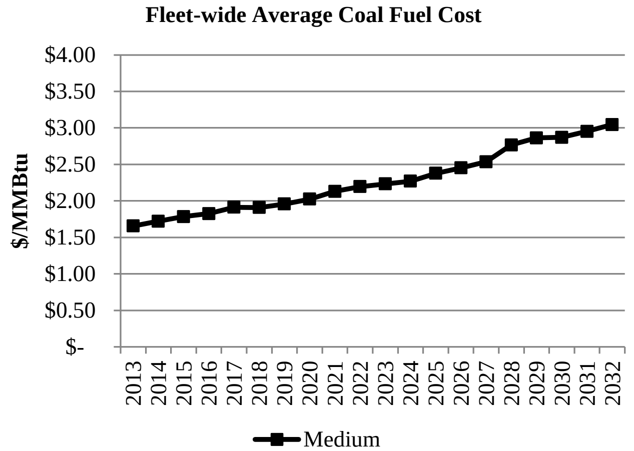
Case C-10 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





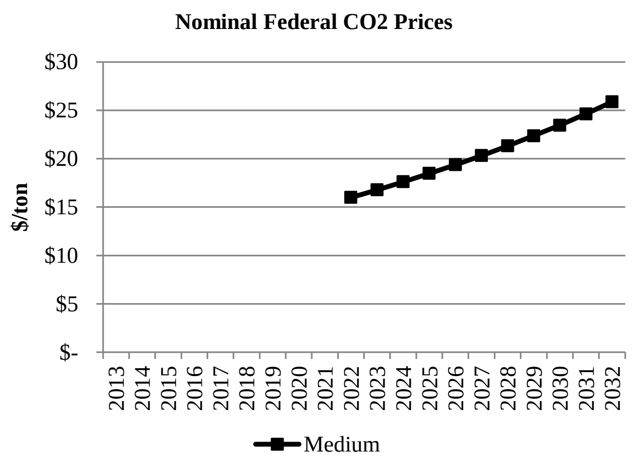
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Case C-10 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Case C-10 will apply stringent case Regional Haze investments patterned after prospective federal implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
DJ 1	WY	LNB	2016
DJ 2	WY	LNB	2018
DJ 3	WY	SNCR	2017
J. Bridger 1	WY	SCR	2017
J. Bridger 2	WY	SCR	2017
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Wyodak	WY	SNCR	2017
Wyodak	WY	SCR	2025
Hunter 1	UT	BH, LNB	2014
Hunter 1	UT	SCR	2018
Hunter 2	UT	SCR	2017
Hunter 3	UT	SCR	2020

Theme: Environmental Policy
Case: C-10 (Stringent Regional Haze, Med Gas, Med CO_2 & Coal, No RPS)

Coal Unit	State	Technology*	Year
Huntington 1	UT	SCR	2018
Huntington 2	UT	SCR	2017
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 1	CO	SCR	2024
Craig 2	CO	SCR	2016
Colstrip 3	MT	SCR	2023
Colstrip 4	MT	SCR	2024
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-10 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-10 does not include any federal RPS requirements.

State RPS

Case C-10 does not include any state RPS requirements.

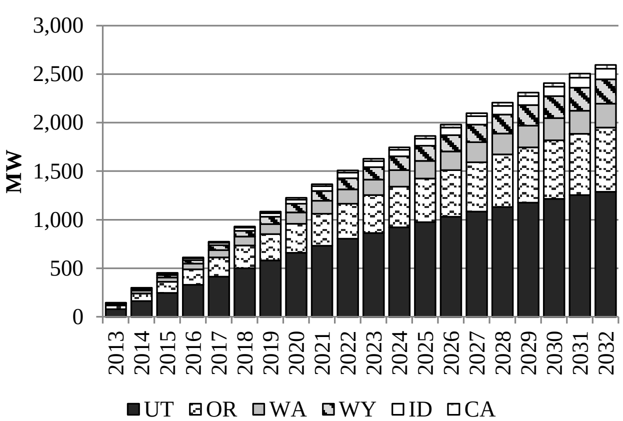
Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.

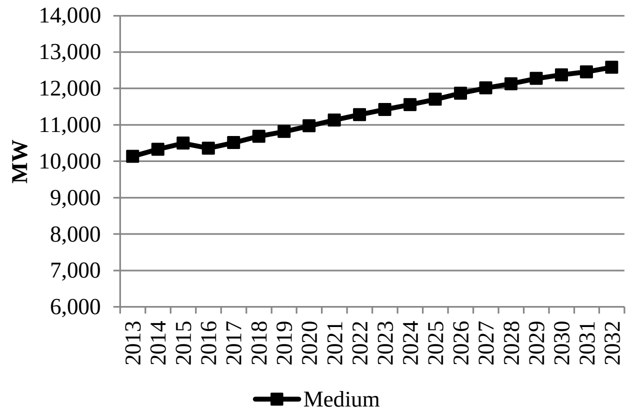
Class 2 DSM Cumulative Achievable Potential



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.

Coincident System Peak Load



Resource Specific

There are no other specific resource constraints that will be applied to this case.

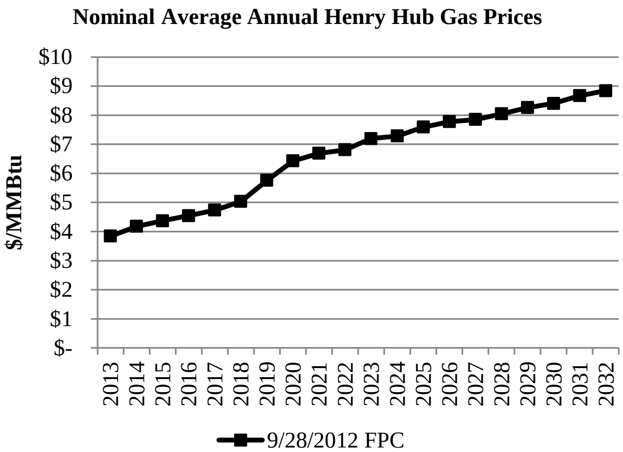
Theme: Environmental Policy
Case: C-11 (Stringent Regional Haze, Med Gas, Med CO_2 & Coal, With RPS)

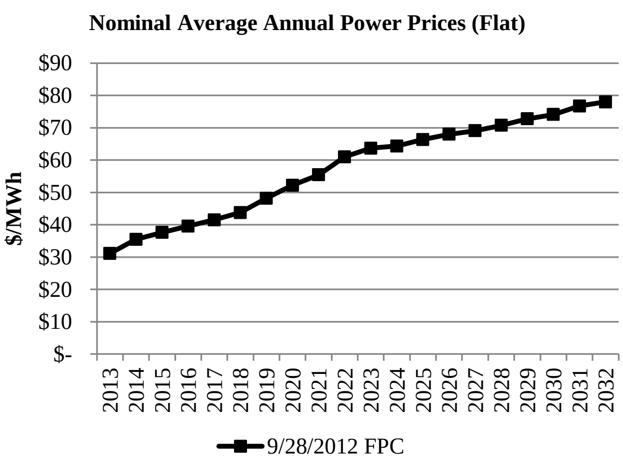
Description

Case C-11 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

Forward Price Curve

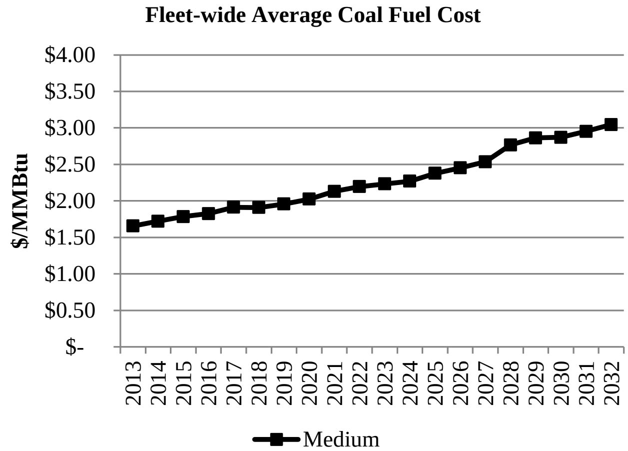
Case C-11 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





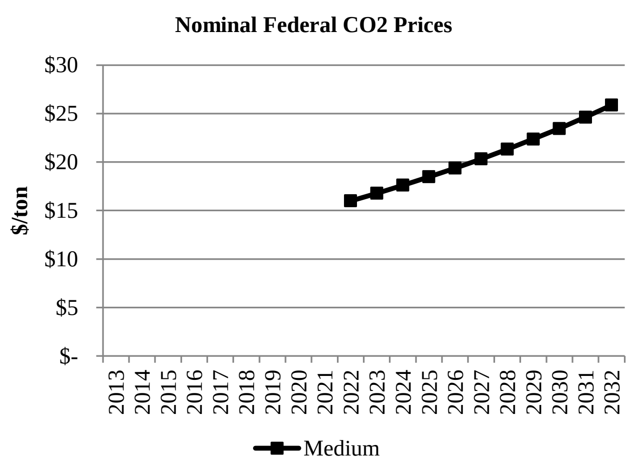
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Case C-11 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Case C-11 will apply stringent case Regional Haze investments patterned after prospective federal implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
DJ 1	WY	LNB	2016
DJ 2	WY	LNB	2018
DJ 3	WY	SNCR	2017
J. Bridger 1	WY	SCR	2017
J. Bridger 2	WY	SCR	2017
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Wyodak	WY	SNCR	2017
Wyodak	WY	SCR	2025
Hunter 1	UT	BH, LNB	2014
Hunter 1	UT	SCR	2018
Hunter 2	UT	SCR	2017
Hunter 3	UT	SCR	2020

Theme: Environmental Policy
Case: C-11 (Stringent Regional Haze, Med Gas, Med CO_2 & Coal, With RPS)

Coal Unit	State	Technology*	Year
Huntington 1	UT	SCR	2018
Huntington 2	UT	SCR	2017
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 1	CO	SCR	2024
Craig 2	CO	SCR	2016
Colstrip 3	MT	SCR	2023
Colstrip 4	MT	SCR	2024
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-11 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-11 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

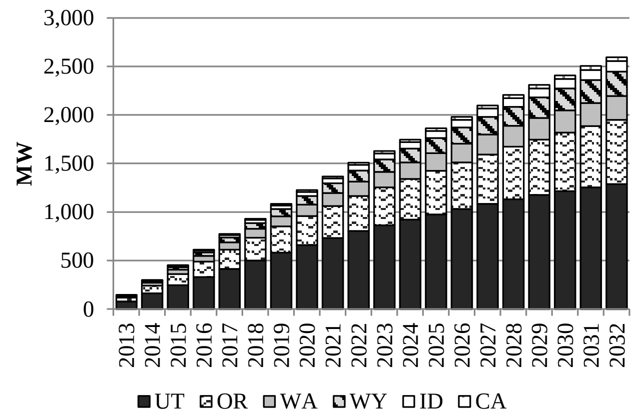
Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.

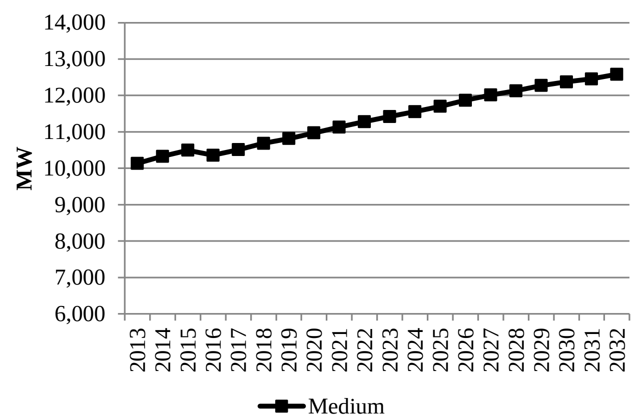
Class 2 DSM Cumulative Achievable Potential



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.

Coincident System Peak Load



Resource Specific

There are no other specific resource constraints that will be applied to this case.

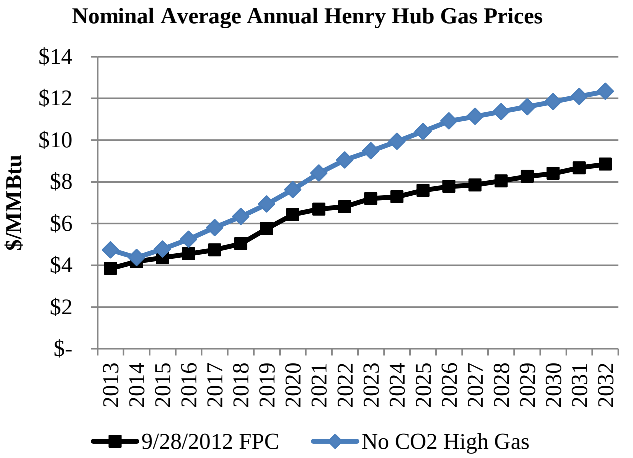
Theme: Environmental Policy
Case: C-12 (Stringent Regional Haze, High Gas, No CO_2, Low Coal, No RPS)

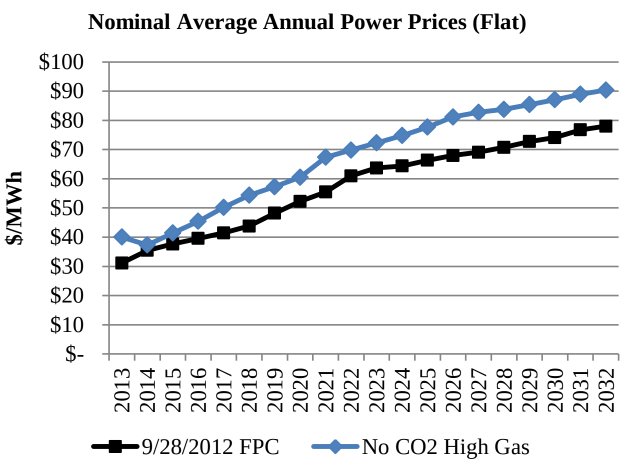
Description

Case C-12 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

Forward Price Curve

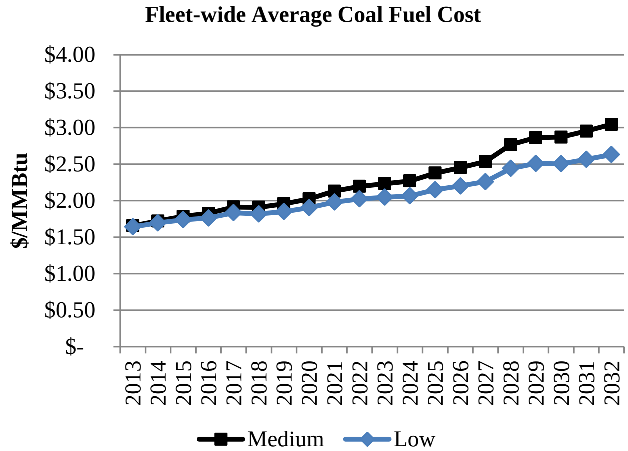
Case C-12 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.





Coal Fuel Costs

Case C-12 low coal costs are shown alongside the medium coal costs in the figure below.



Federal CO_2 Policy/Price Signal

Case C-12 does not have a federal CO_2 price assumption.

Regional Haze

Case C-12 will apply stringent case Regional Haze investments patterned after prospective federal implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
DJ 1	WY	LNB	2016
DJ 2	WY	LNB	2018
DJ 3	WY	SNCR	2017
J. Bridger 1	WY	SCR	2017
J. Bridger 2	WY	SCR	2017
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Wyodak	WY	SNCR	2017
Wyodak	WY	SCR	2025
Hunter 1	UT	BH, LNB	2014
Hunter 1	UT	SCR	2018
Hunter 2	UT	SCR	2017
Hunter 3	UT	SCR	2020
Huntington 1	UT	SCR	2018
Huntington 2	UT	SCR	2017
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 1	CO	SCR	2024
Craig 2	CO	SCR	2016
Colstrip 3	MT	SCR	2023
Colstrip 4	MT	SCR	2024
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-12 will include estimated costs to achieve compliance with the following:

Theme: Environmental Policy
Case: C-12 (Stringent Regional Haze, High Gas, No CO_2, Low Coal, No RPS)

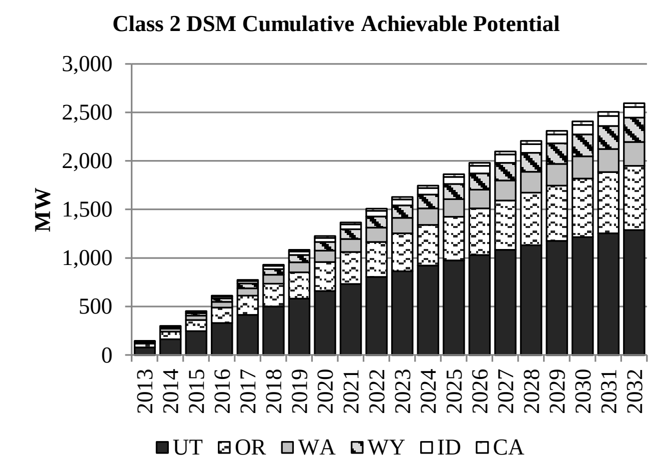
- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS
Case C-12 does not include any federal RPS requirements.

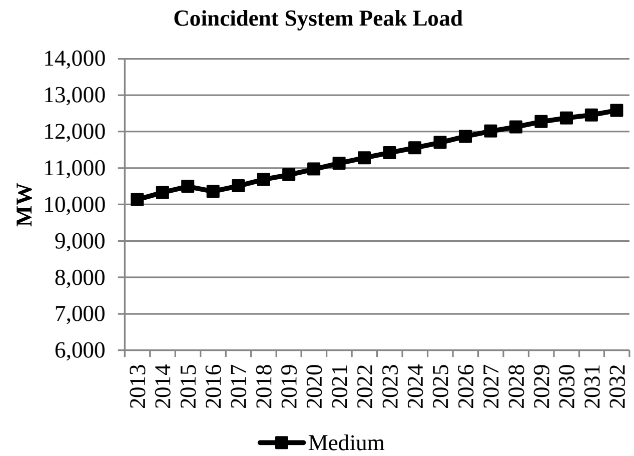
State RPS
Case C-12 does not include any state RPS requirements.

Federal Tax Incentives
- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific
There are no other specific resource constraints that will be applied to this case.

Theme: Environmental Policy
Case: C-13 (Stringent Regional Haze, High Gas, No CO_2, Low Coal, With RPS)

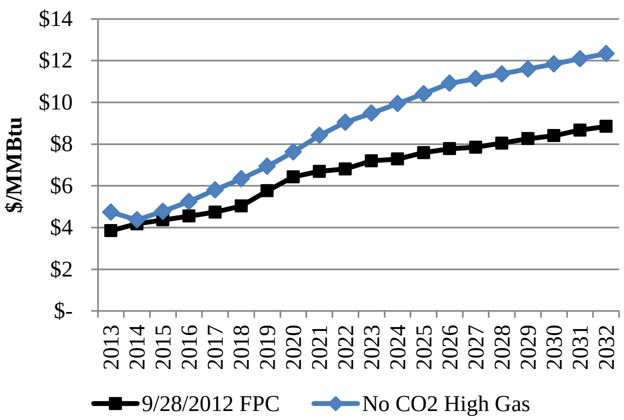
Description

Case C-13 is one of eleven core cases in the "Environmental Policy" theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

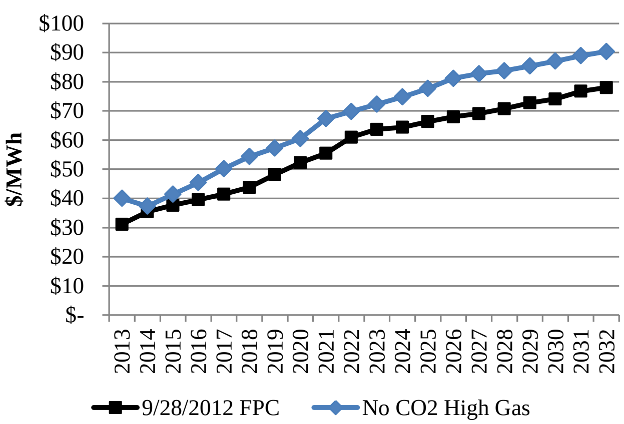
Forward Price Curve

Case C-13 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



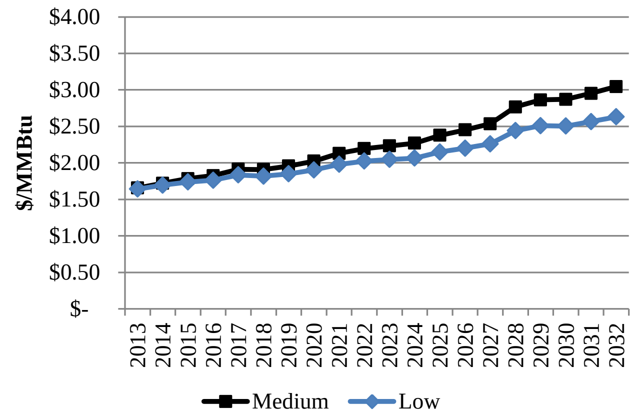
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Case C-13 low coal costs are shown alongside the medium coal costs in the figure below.

Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-13 does not have a federal CO_2 price assumption.

Regional Haze

Case C-13 will apply stringent case Regional Haze investments patterned after prospective federal implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
DJ 1	WY	LNB	2016
DJ 2	WY	LNB	2018
DJ 3	WY	SNCR	2017
J. Bridger 1	WY	SCR	2017
J. Bridger 2	WY	SCR	2017
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Wyodak	WY	SNCR	2017
Wyodak	WY	SCR	2025
Hunter 1	UT	BH, LNB	2014
Hunter 1	UT	SCR	2018
Hunter 2	UT	SCR	2017
Hunter 3	UT	SCR	2020
Huntington 1	UT	SCR	2018
Huntington 2	UT	SCR	2017
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 1	CO	SCR	2024
Craig 2	CO	SCR	2016
Colstrip 3	MT	SCR	2023
Colstrip 4	MT	SCR	2024
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-13 will include estimated costs to achieve compliance with the following:

Theme: Environmental Policy
Case: C-13 (Stringent Regional Haze, High Gas, No CO_2, Low Coal, With RPS)

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-13 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

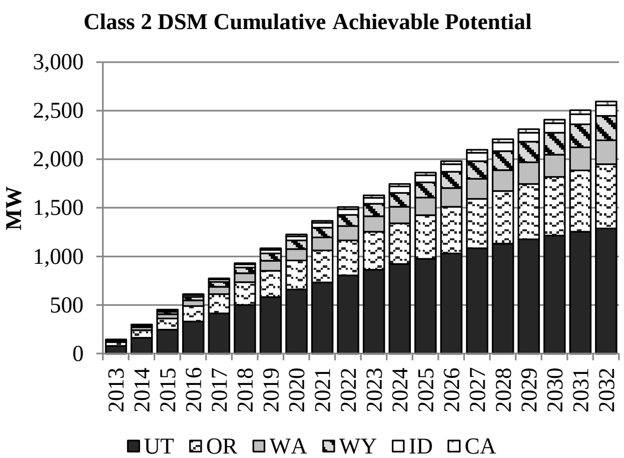
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

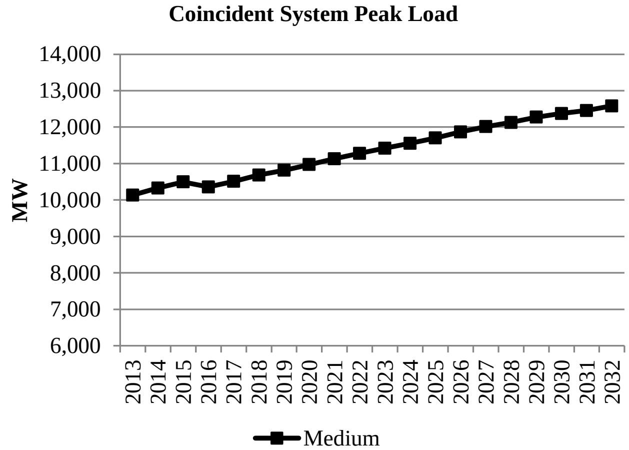
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

Theme: Environmental Policy
Case: C-14 (Base Regional Haze, Med Gas, U.S. Hard Cap, Med Coal, With RPS)

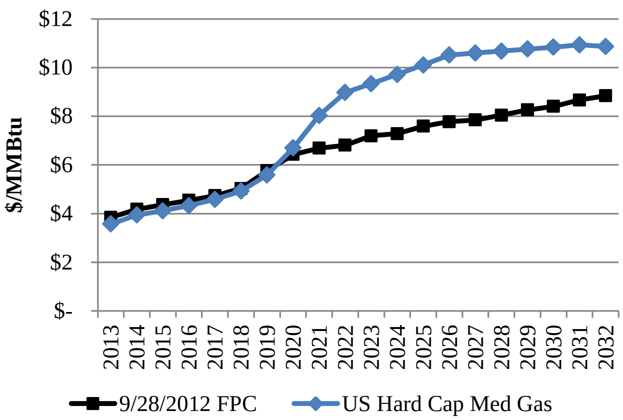
Description

Case C-14 is one of eleven core cases in the “Environmental Policy” theme (Cases C-4 through C-14). These cases are characterized by varying combinations of commodity market prices, CO_2 costs, RPS requirements, and Regional Haze requirements. This structure will enable reporting on the conditions that might require early retirement and resource replacement or conversion to natural gas for existing coal-fueled resources.

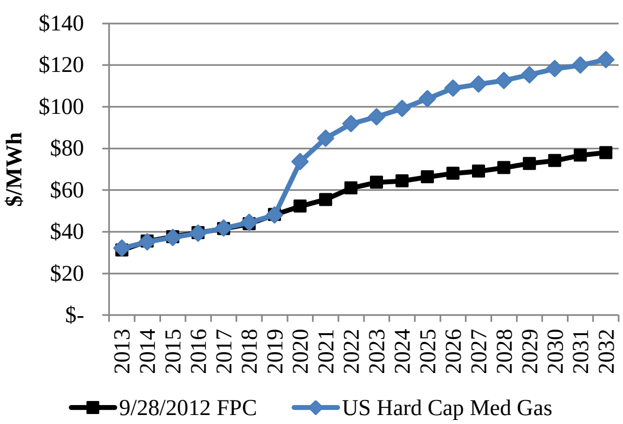
Forward Price Curve

Case C-14 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



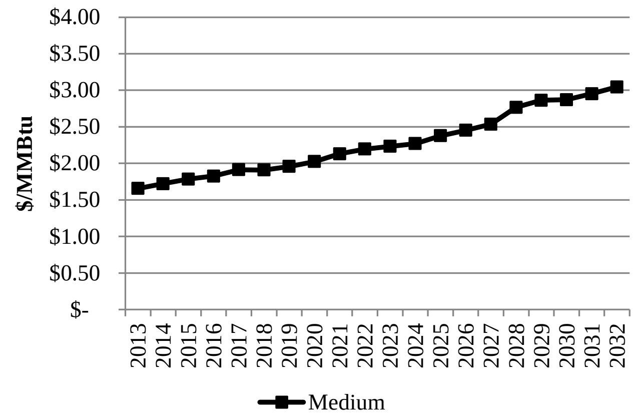
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

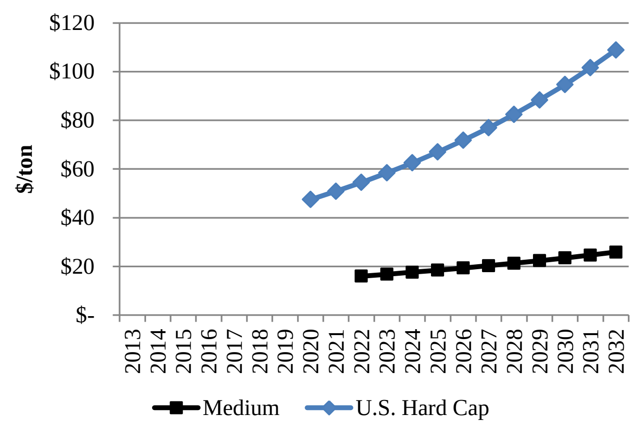
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-14 includes CO_2 prices required for the U.S. power sector to achieve an 80% reduction in emissions by 2050. Prices start in 2020 at approximately $47/ton rising to approximately $109/ton by 2032. These U.S. hard cap CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.

Nominal Federal CO2 Prices



Regional Haze

Case C-14 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023

Theme: Environmental Policy
Case: C-14 (Base Regional Haze, Med Gas, U.S. Hard Cap, Med Coal, With RPS)

Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-14 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-14 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

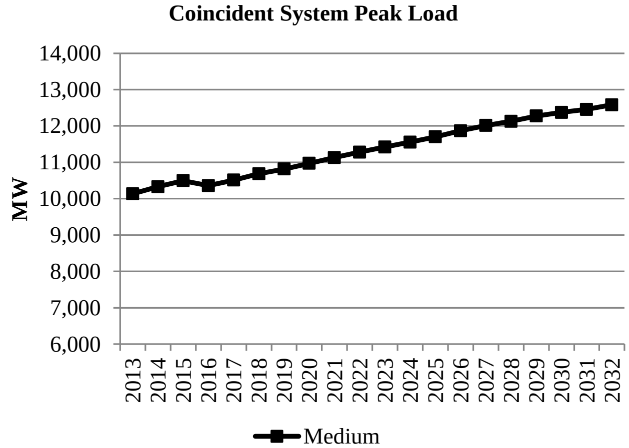
- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)

Supply curves will be adjusted from the base assumptions by accelerating ramp rates with resource selection up to the achievable potential identified in the 2012 potential study. Measure and market ramp rates are adjusted from the base case assumptions to allow selection of up to 2% of 2011 actual sales in each state. After discretionary resources are exhausted, annual opportunities decrease significantly, with remaining resources from equipment upgrades and new construction. Class 2 resources that are not selected in any given year are not available for selection in future years.

Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



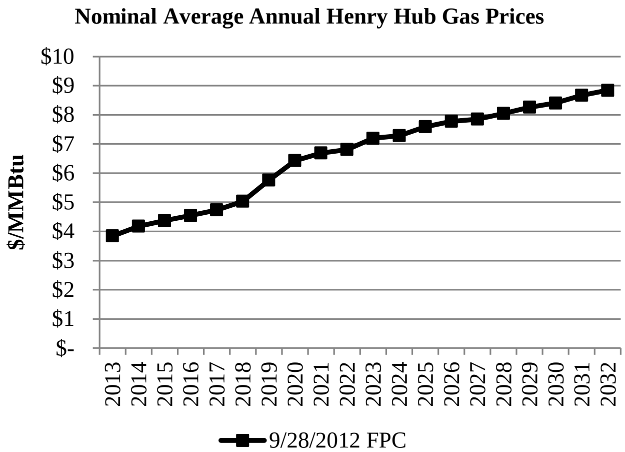
Resource Specific

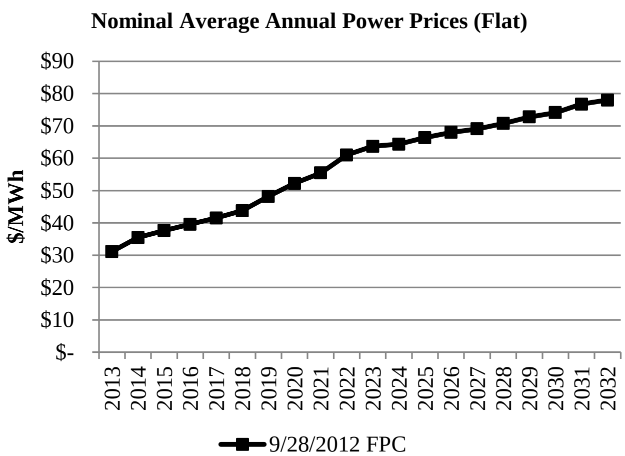
There are no other specific resource constraints that will be applied to this case.

Theme: Targeted Resources
Case: C-15 (No Thermal Base Load)

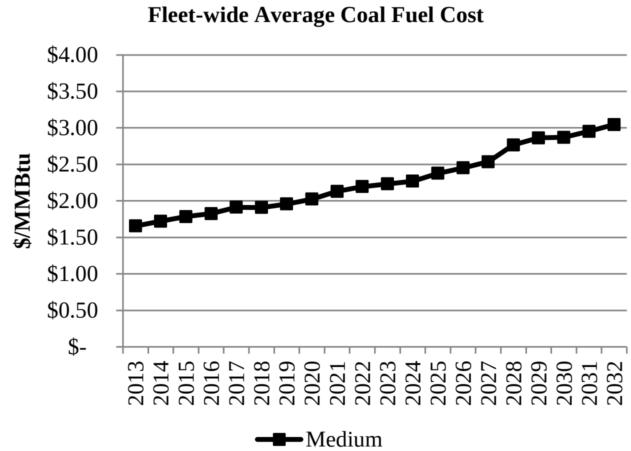
Description
Case C-15 is one of five core cases in the "Targeted Resources" theme (Cases C-15 through C-18). These cases are characterized by alternative assumptions for specific resource types to understand how those assumptions influence resource portfolios, costs and stochastic risk.

Forward Price Curve
Case C-15 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

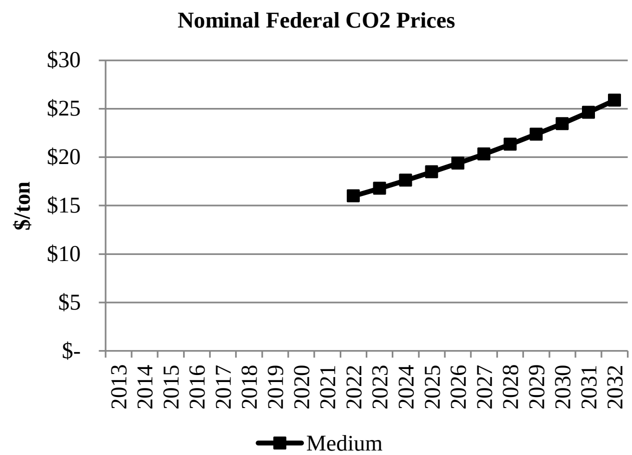




Coal Fuel Costs
Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal
Case C-15 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze
Case C-15 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-15 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-15 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

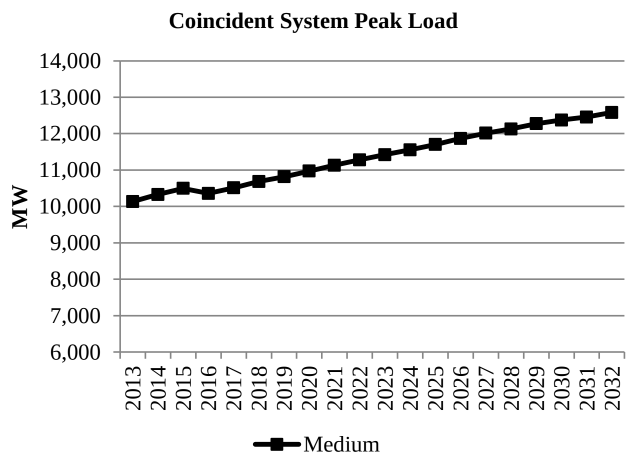
- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)

Supply curves will be adjusted from the base assumptions by accelerating ramp rates with resource selection up to the achievable potential identified in the 2012 potential study. Measure and market ramp rates are adjusted from the base case assumptions to allow selection of up to 2% of 2011 actual sales in each state. After discretionary resources are exhausted, annual opportunities decrease significantly, with remaining resources from equipment upgrades and new construction. Class 2 resources that are not selected in any given year are not available for selection in future years.

Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

All base load thermal resources (gas-fired CCCTs) will be excluded as potential resource alternatives.

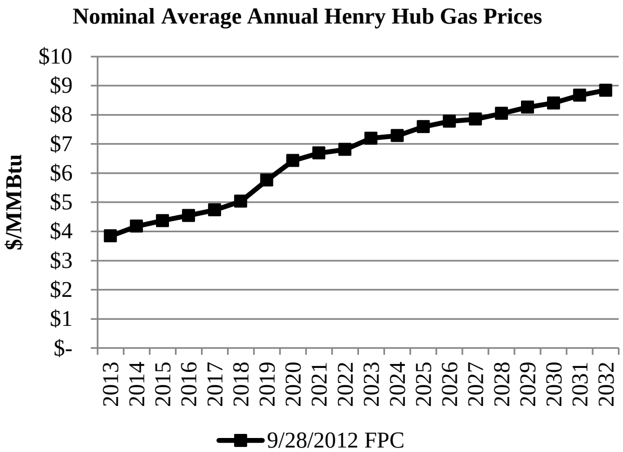
Theme: Targeted Resources
Case: C-16 (Geothermal RPS Strategy)

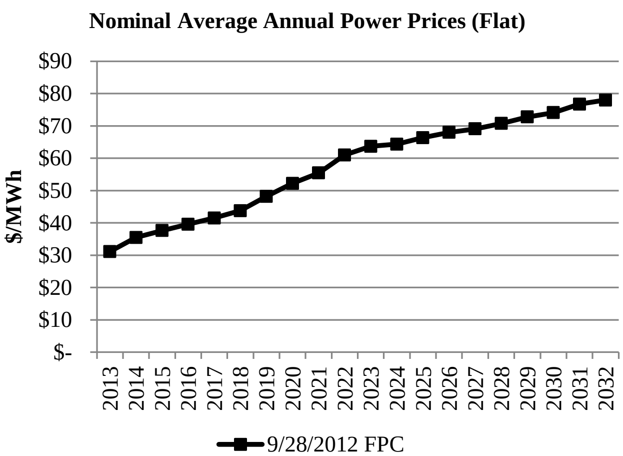
Description

Case C-16 is one of five core cases in the "Targeted Resources" theme (Cases C-15 through C-18). These cases are characterized by alternative assumptions for specific resource types to understand how those assumptions influence resource portfolios, costs and stochastic risk.

Forward Price Curve

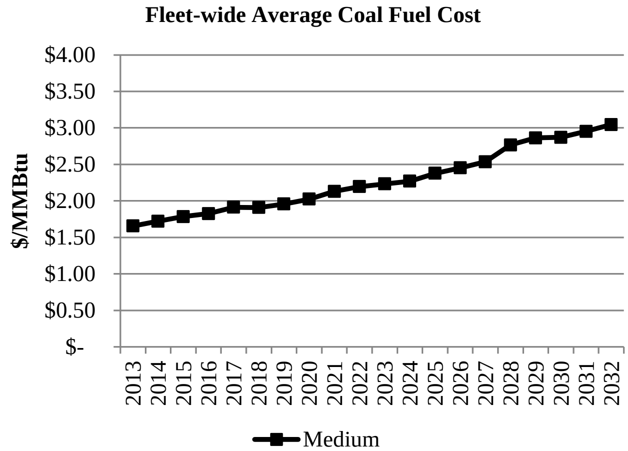
Case C-16 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





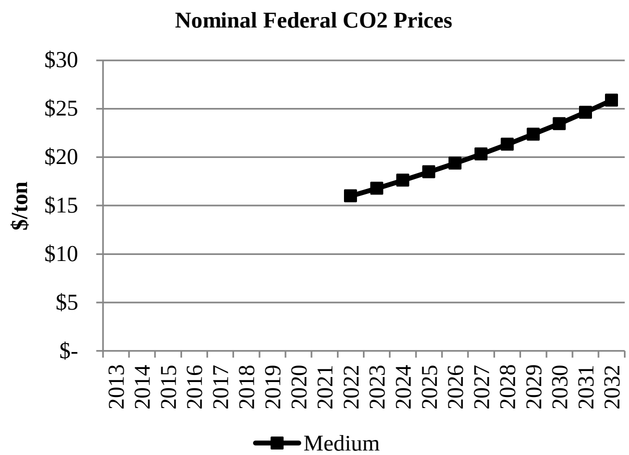
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Case C-16 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Case C-16 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

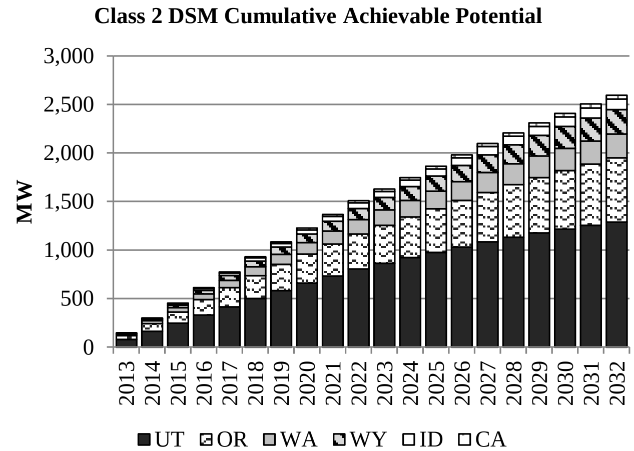
Other Non-CO_2 Environmental Policy Assumptions
Case C-16 will include estimated costs to achieve compliance with the following:
- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS
Case C-16 will include the following federal RPS assumptions:
- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

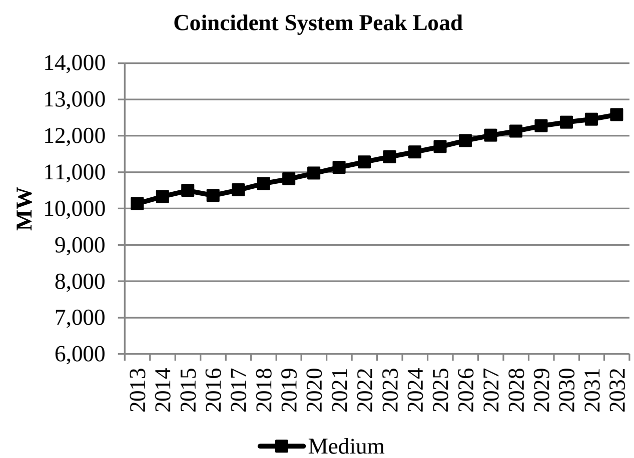
State RPS
Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives
- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific
State and federal RPS assumptions will be met with geothermal resources at five sites identified in the 2011 Geothermal Information Request report prepared by Black & Veatch (B&V Report). Costs will reflect PPA pricing consistent with recent RFP activity. The total geothermal capacity available is 145 MW. Any RPS compliance shortfall that cannot be met with geothermal resource generation will be met with other renewable resource alternatives.

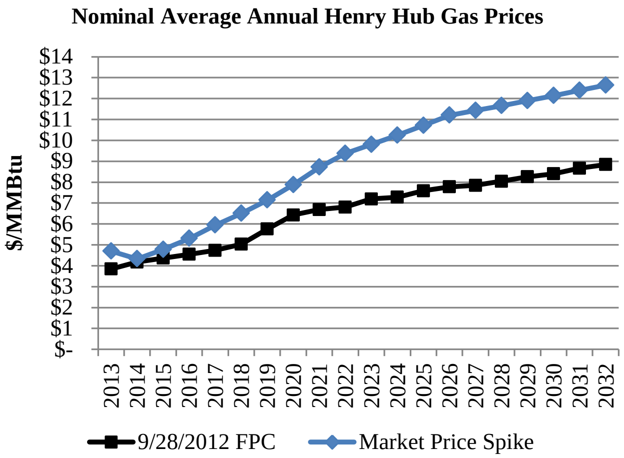
Theme: Targeted Resources
Case: C-17 (Market Price Spike)

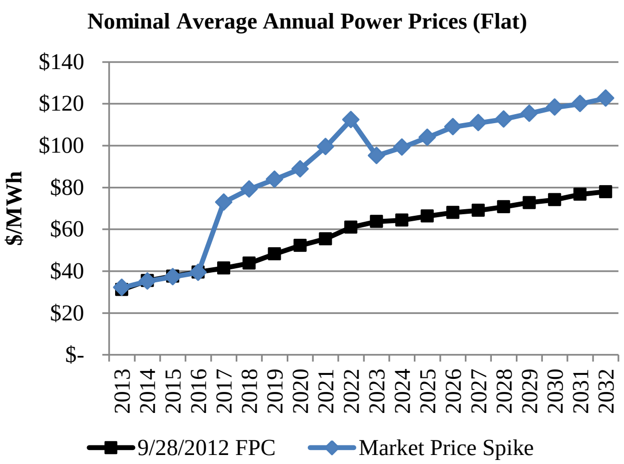
Description

Case C-17 is one of five core cases in the “Targeted Resources” theme (Cases C-15 through C-18). These cases are characterized by alternative assumptions for specific resource types to understand how those assumptions influence resource portfolios, costs and stochastic risk.

Forward Price Curve

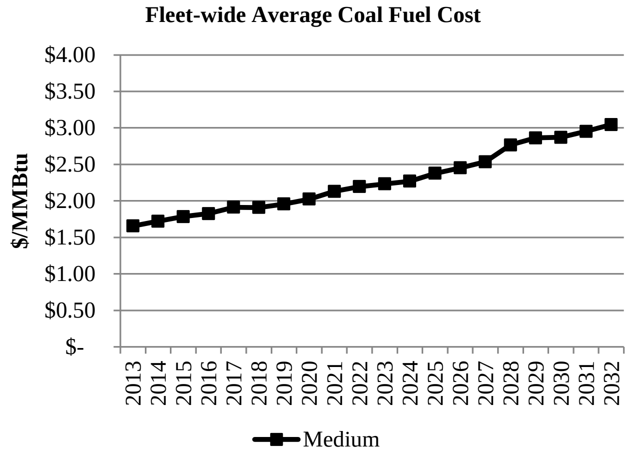
Case C-17 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.





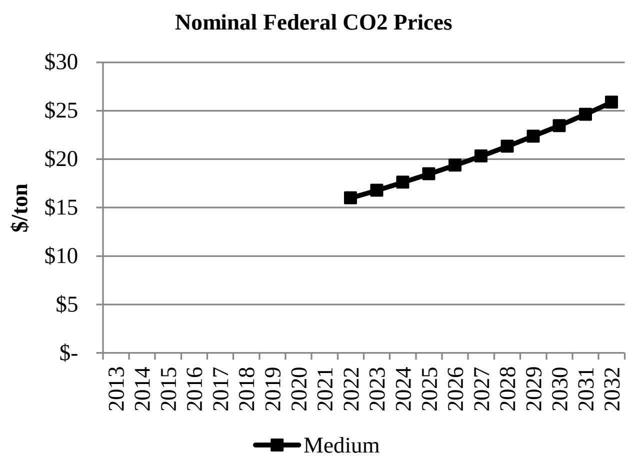
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Case C-17 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Case C-17 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

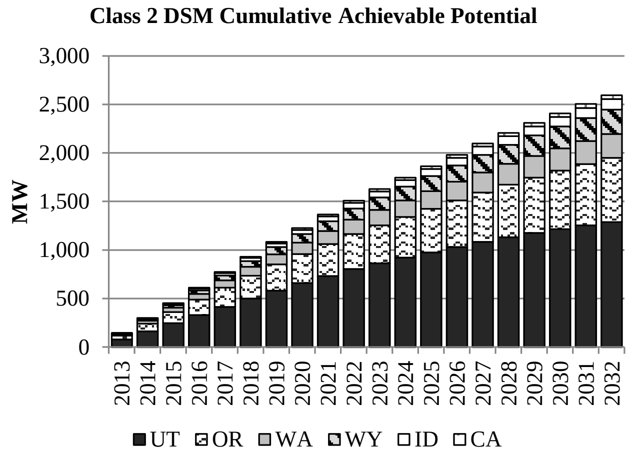
Other Non-CO_2 Environmental Policy Assumptions
Case C-17 will include estimated costs to achieve compliance with the following:
- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS
Case C-17 will include the following federal RPS assumptions:
- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

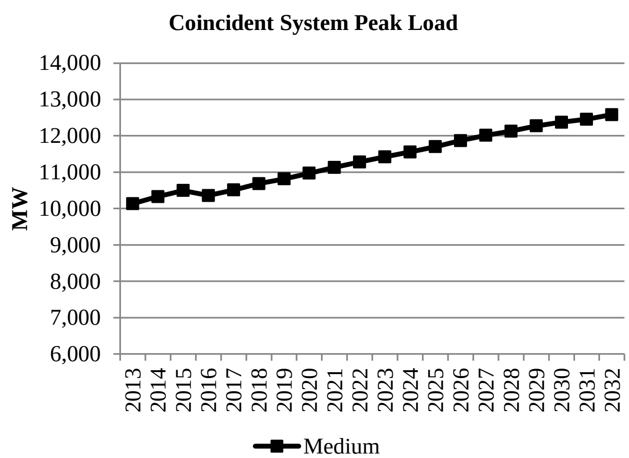
State RPS
Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives
- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific
Forward price curves applied in the case reflect high gas price assumptions and an incremental power price increase over the period 2017 – 2022 at 50% on-peak and 30% off-peak.

Theme: Targeted Resources
Case: C-18 (Clean Energy Bookend)

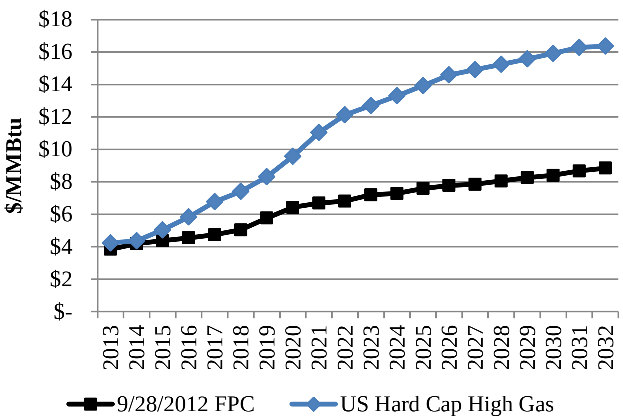
Description

Case C-18 is one of five core cases in the "Targeted Resources" theme (Cases C-15 through C-18). These cases are characterized by alternative assumptions for specific resource types to understand how those assumptions influence resource portfolios, costs and stochastic risk.

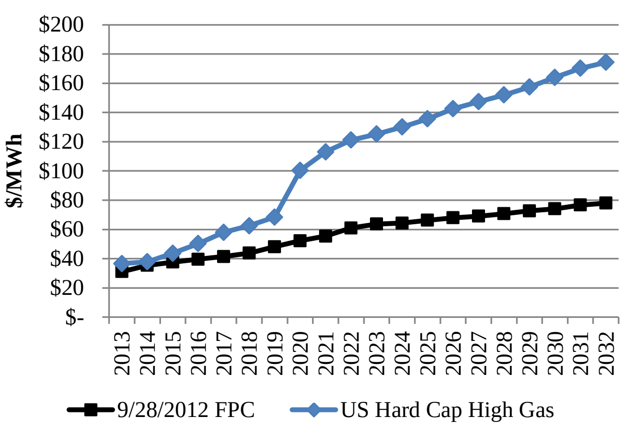
Forward Price Curve

Case C-18 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



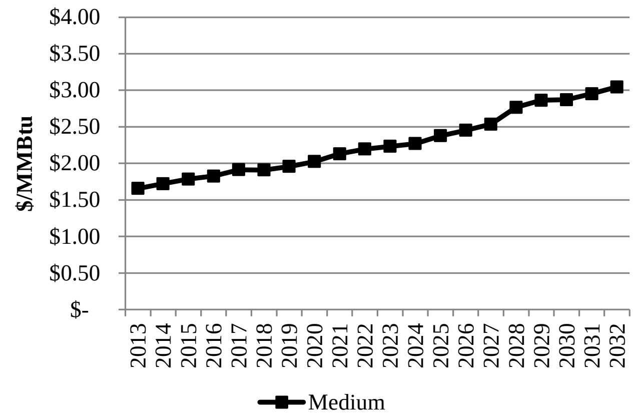
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

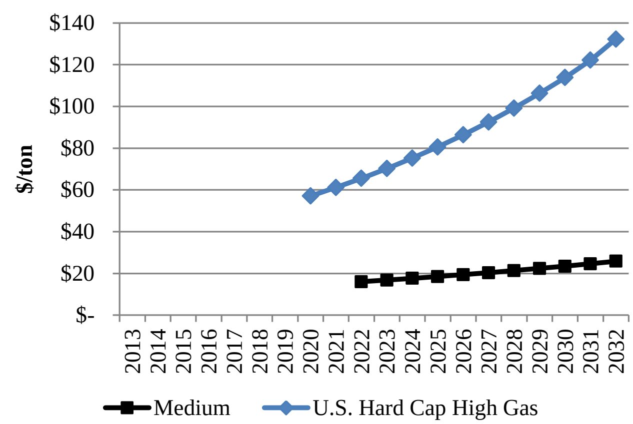
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-18 includes CO_2 prices required for the U.S. power sector to achieve an 80% reduction in emissions by 2050. Prices start in 2020 at approximately $57/ton rising to approximately $132/ton by 2032. These U.S. hard cap CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.

Nominal Federal CO2 Prices



Regional Haze

Case C-18 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023

Theme: Targeted Resources
Case: C-18 (Clean Energy Bookend)

Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-18 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-18 does not include any federal RPS requirements.

State RPS

Case C-18 does not include any state RPS requirements.

Federal Tax Incentives

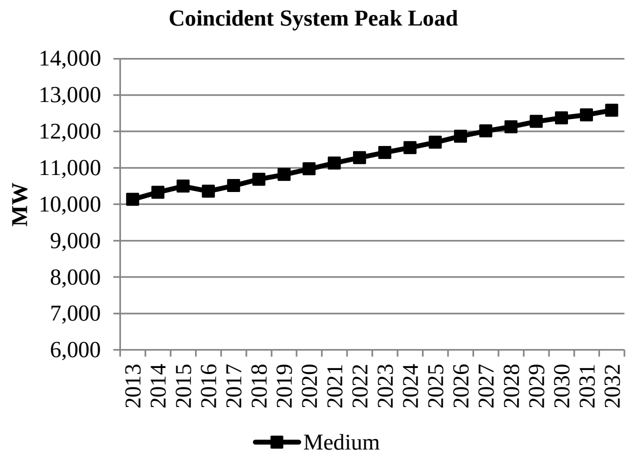
- PTCs are extended through 2019
- ITCs are extended through 2019

Energy Efficiency (Class 2 DSM)

Supply curves will be adjusted from the base assumptions by accelerating ramp rates with resource selection up to the achievable potential identified in the 2012 potential study. Measure and market ramp rates are adjusted from the base case assumptions to allow selection of up to 2% of 2011 actual sales in each state. After discretionary resources are exhausted, annual opportunities decrease significantly, with remaining resources from equipment upgrades and new construction. Class 2 resources that are not selected in any given year are not available for selection in future years.

Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

Theme: Transmission
Case: C-19 (Energy Gateway Segment D Alternative)

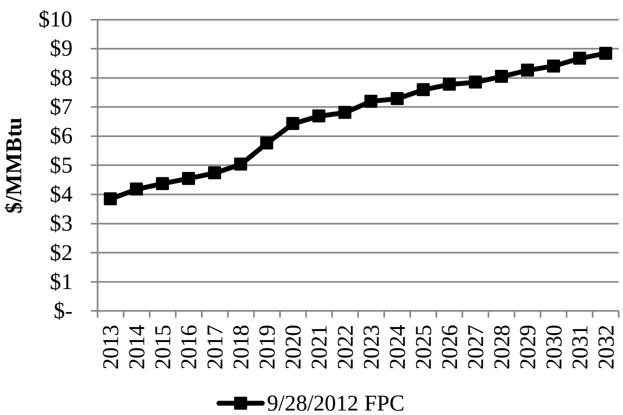
Description

Case C-19 represents an incremental Energy Gateway core case that will be implemented among all Energy Gateway Scenarios but for the Reference Case, which does not include segment D. This case evaluates an assumed third party transmission can be purchased from a newly built line connecting Wyoming with the Populous substation in Idaho.

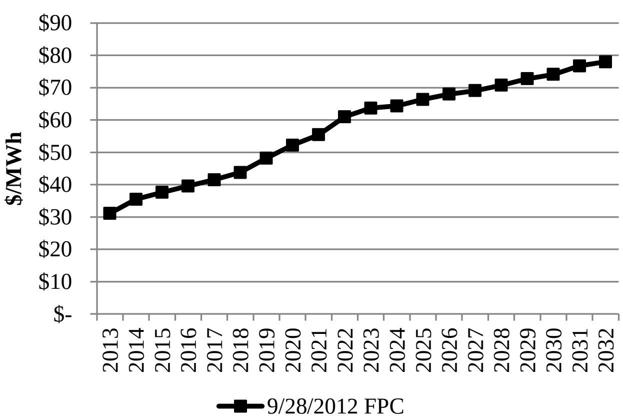
Forward Price Curve

Case C-19 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices



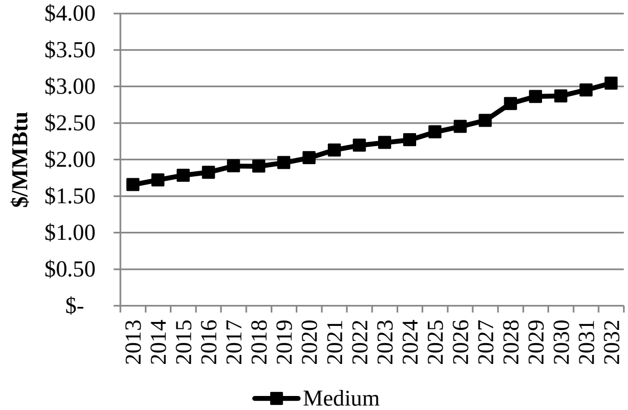
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

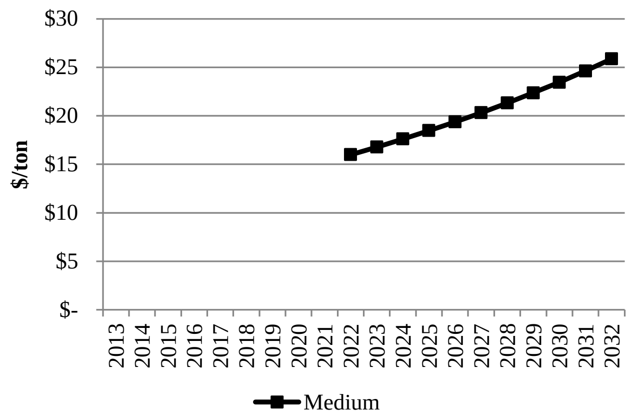
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Case C-19 includes medium CO_2 prices starting 2022 at \$16/ton rising to approximately \$26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze

Case C-19 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Transmission
Case: C-19 (Energy Gateway Segment D Alternative)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Case C-19 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Case C-19 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

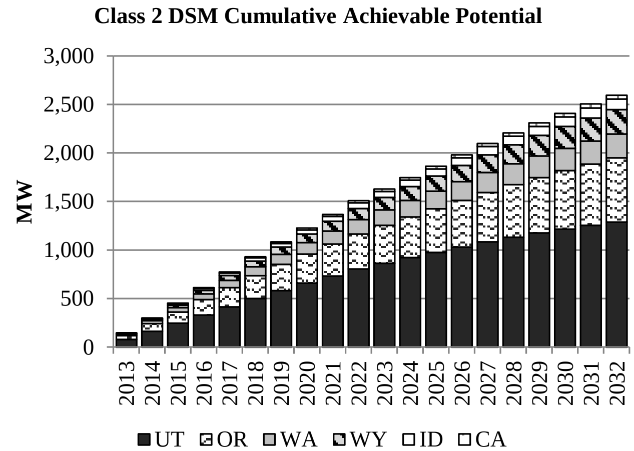
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

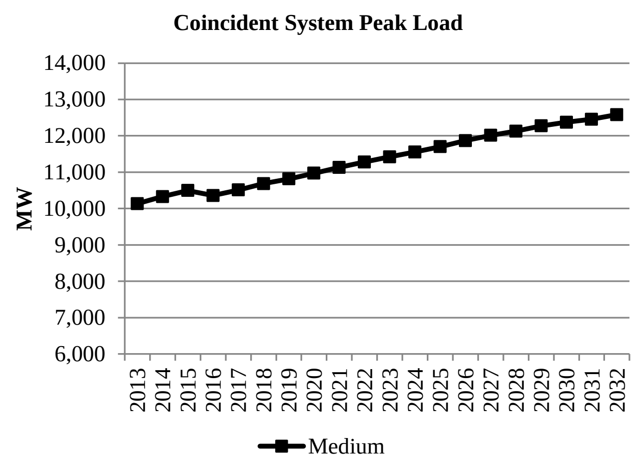
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Segment D Transmission Alternative

Wheeling costs applied to this case total $14.15/kW-mo for 900 MW and reflect the following assumptions:

- Costs are patterned after the only know project proposed that generally fits the targeted scenario, which is the proposed Zephyr DC project from Wyoming to Las Vegas.
- Total transfer capability is 3,000 MW, and 2,100 MW is paid for by other parties (wheeling costs are proportionate to the assumed 900 MW of firm transmission purchased).

Sensitivity Case Fact Sheets

Sensitivity Case Fact Sheets – S-1 to S-10, S-X

Theme: Load Sensitivities
Sensitivity: S-1 (Low Load Forecast)

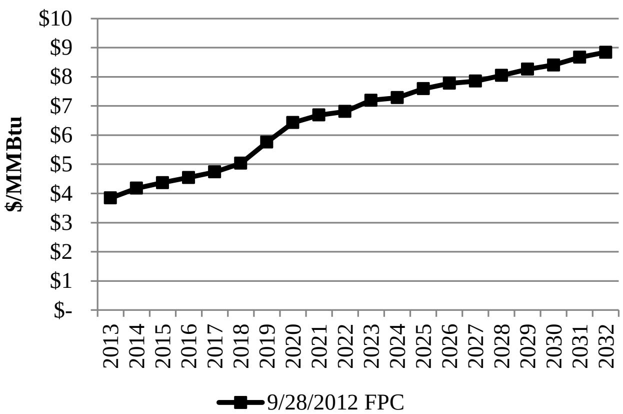
Description

Sensitivity S-1 will be completed assuming a low load forecast. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

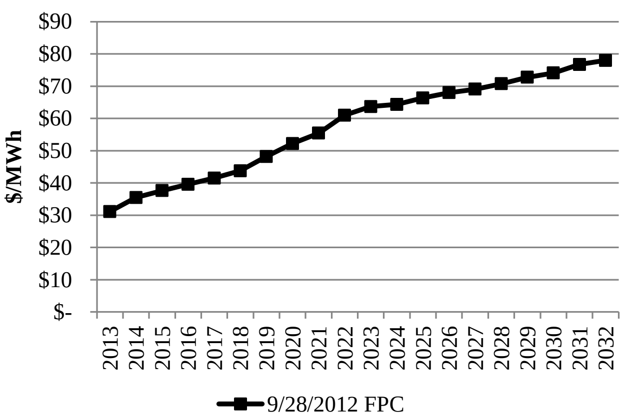
Forward Price Curve

Sensitivity S-1 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices



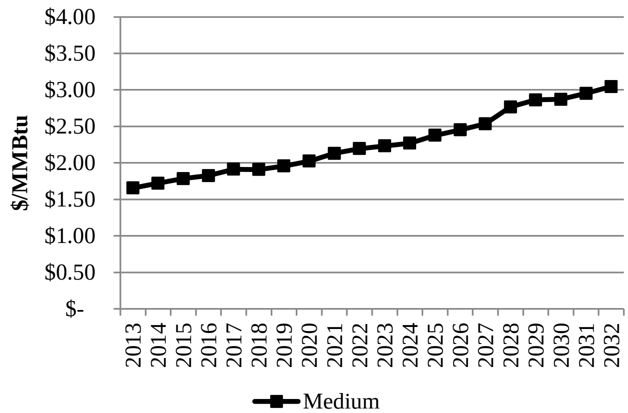
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

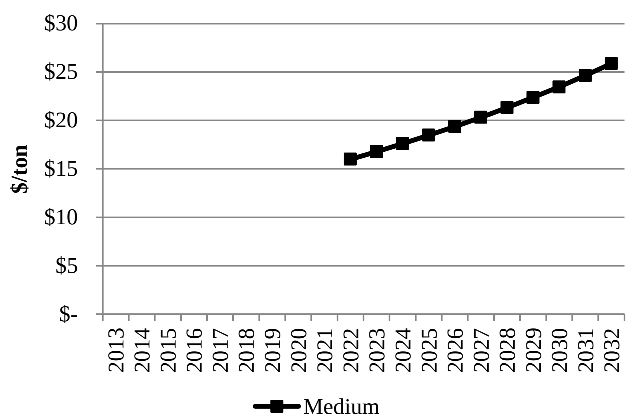
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Sensitivity S-1 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze

Sensitivity S-1 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Load Sensitivities
Sensitivity: S-1 (Low Load Forecast)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-1 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-1 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

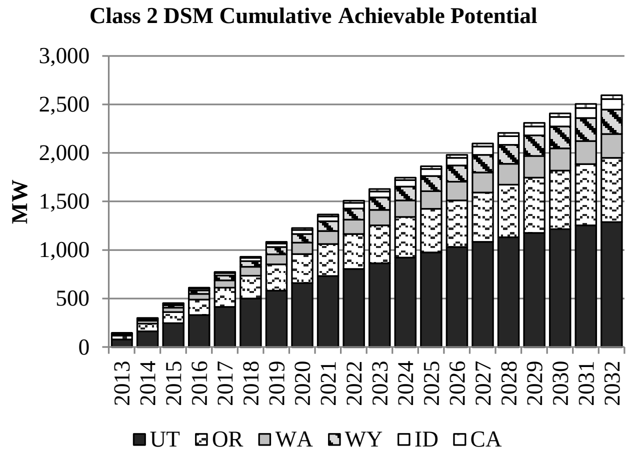
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

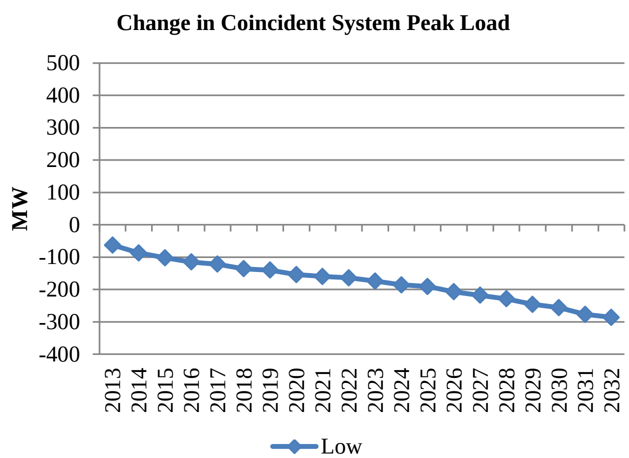
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

A low load forecast derived using low economic driver assumptions will be used. The figure below shows the change in system coincident peak as compared to the medium (base) load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that apply to this sensitivity.

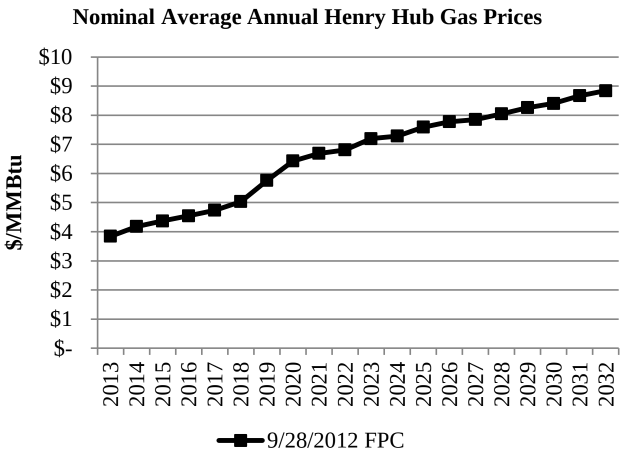
Theme: Load Sensitivities
Sensitivity: S-2 (High Load Forecast)

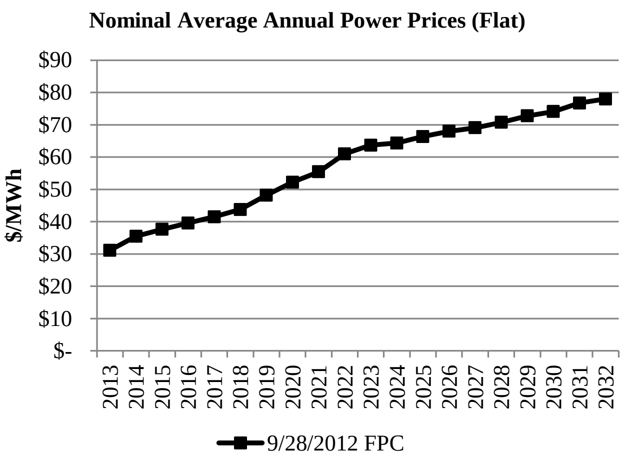
Description

Sensitivity S-2 will be completed assuming a high load forecast. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

Forward Price Curve

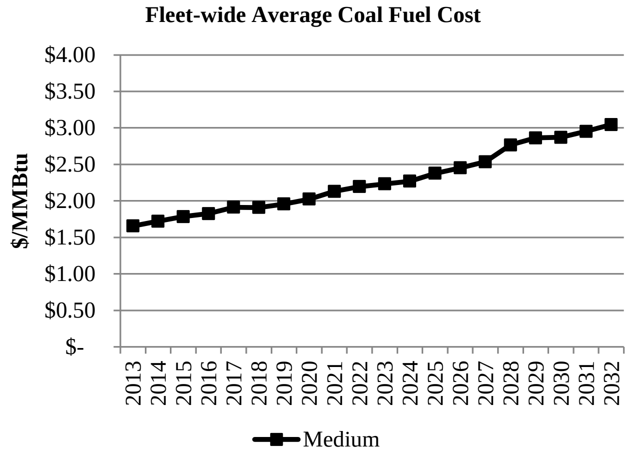
Sensitivity S-2 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





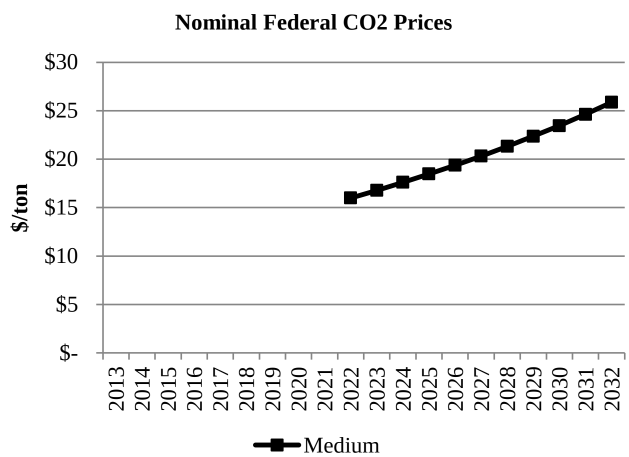
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Sensitivity S-2 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Sensitivity S-2 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Load Sensitivities
Sensitivity: S-2 (High Load Forecast)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-2 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-2 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

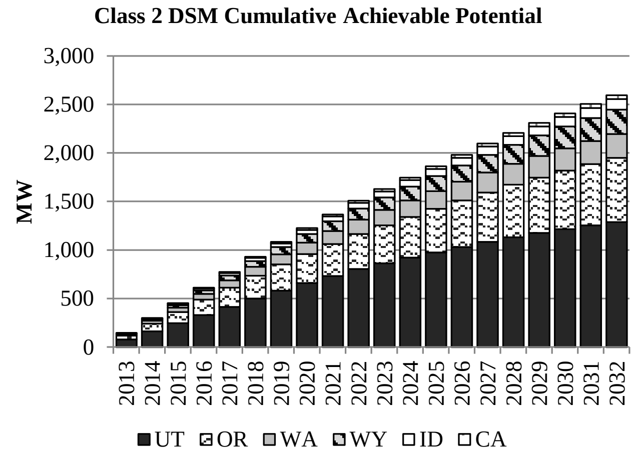
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

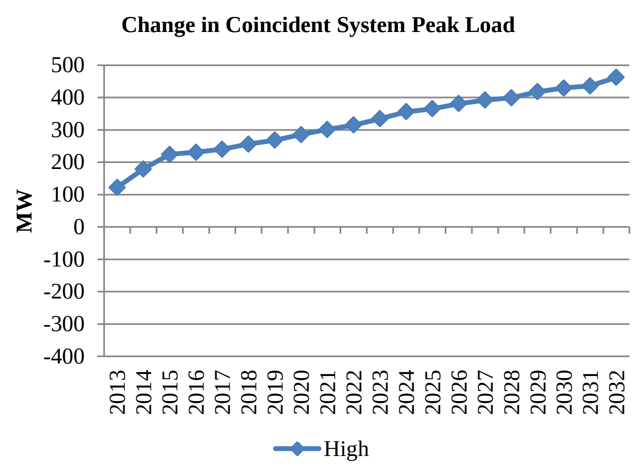
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

A high load forecast derived using high economic drivers and high industrial load growth will be used. The figure below shows the change in system coincident peak as compared to the medium (base) load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

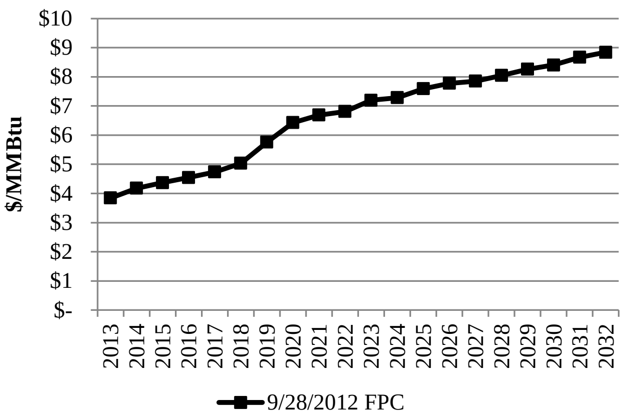
There are no other specific resource constraints that apply to this sensitivity.

Theme: Load Sensitivities
Sensitivity: S-3 (1 in 20 Load)

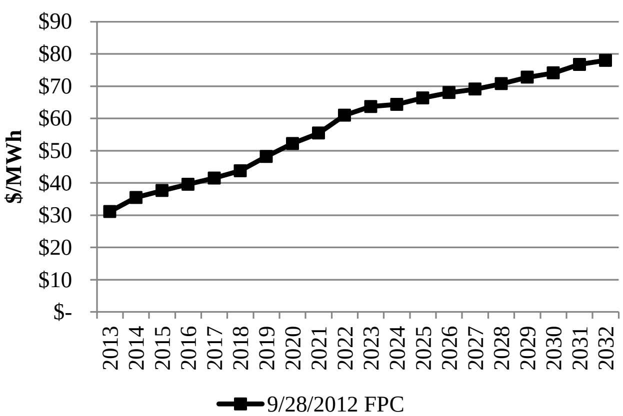
Description
Sensitivity S-3 will be completed assuming a 1 in 20 load forecast. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

Forward Price Curve
Sensitivity S-3 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices

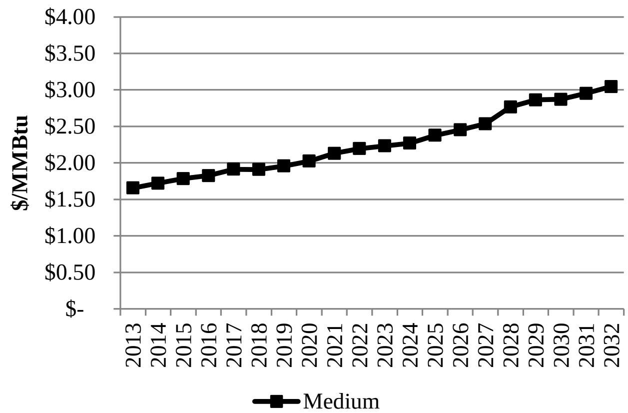


Nominal Average Annual Power Prices (Flat)



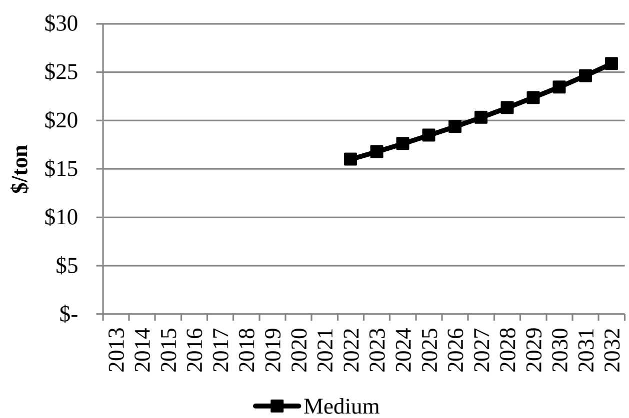
Coal Fuel Costs
Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal
Sensitivity S-3 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze
Sensitivity S-3 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-3 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-3 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

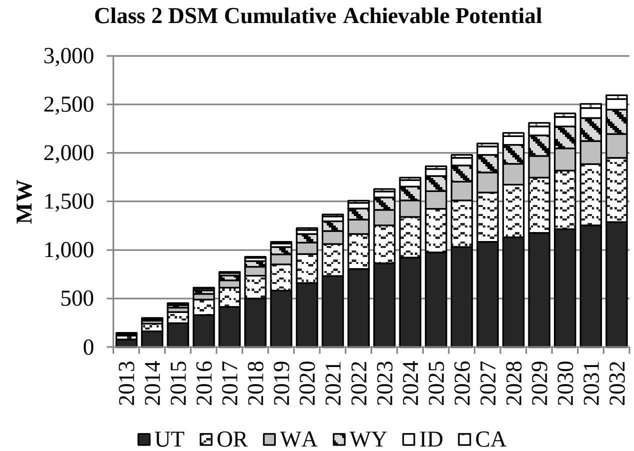
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

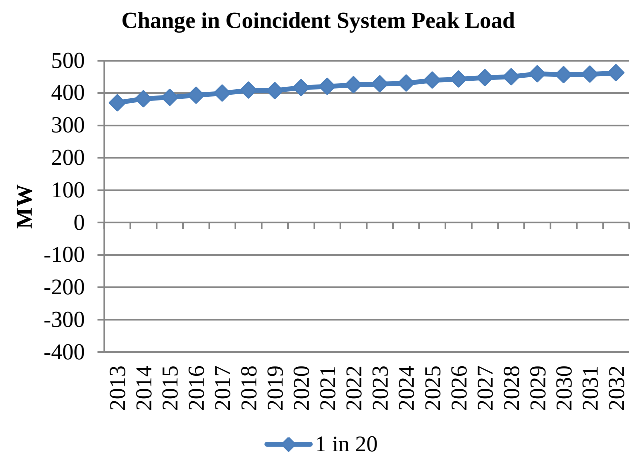
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

A 1 in 20 load forecast reflecting the top peak producing weather over the past 20 years will be used. The figure below shows the change in system coincident peak as compared to the medium (base) load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that apply to this sensitivity.

Theme: Environmental Policy Sensitivities
Sensitivity: S-4 (Hypothetical Regional Haze Compliance Alternative)

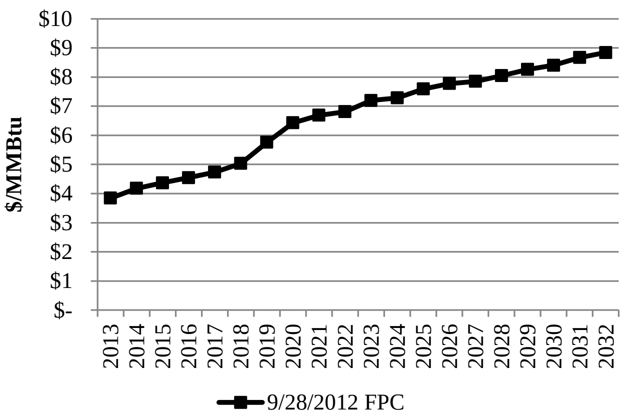
Description

Sensitivity S-4 will explore hypothetical compliance alternatives to near-term Regional Haze-based emissions control investments. For this sensitivity, it is assumed that near-term SCR investments currently required at Jim Bridger Units 3&4 and at Cholla Unit 4 can be avoided if a commitment is made to retire those coal units early. The selection of hypothetical retirement dates in this sensitivity is informed by an evaluation of the cost per ton of pollutant removed; much the same as such information would be factored into a BART analysis. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2. The results of Sensitivity S-4 will be presented in Confidential Volume 3 of the 2013 IRP.

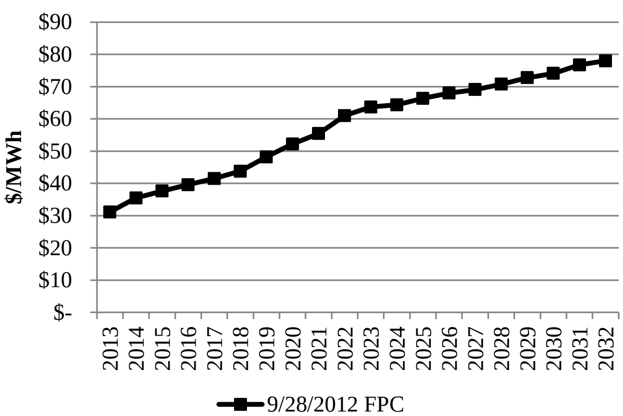
Forward Price Curve

Sensitivity S-4 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices



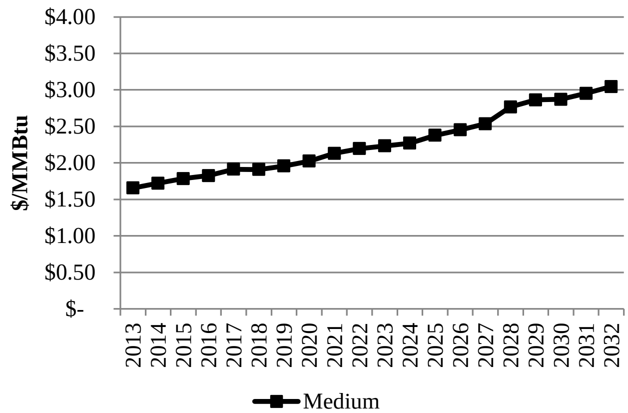
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

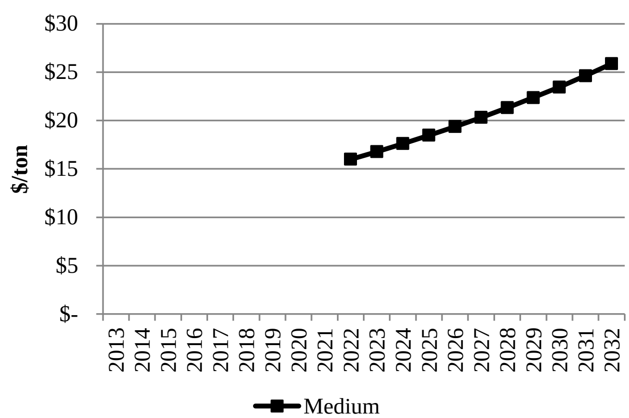
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Sensitivity S-4 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze

For those units that are not being analyzed as part of this sensitivity, base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements will be applied.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Theme: Environmental Policy Sensitivities
Sensitivity: S-4 (Hypothetical Regional Haze Compliance Alternative)

Other Non-CO_2 Environmental Policy Assumptions
Sensitivity S-4 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS
Sensitivity S-4 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

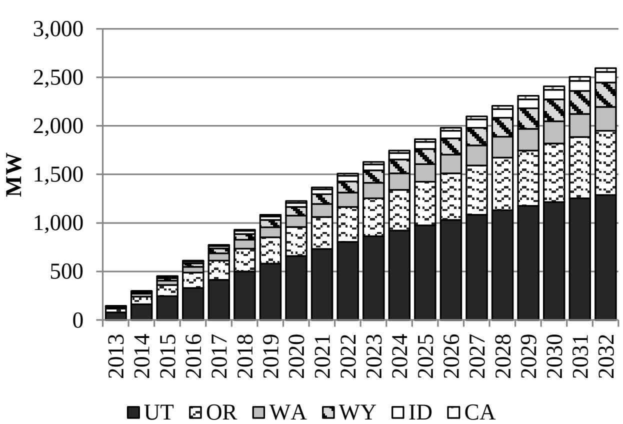
State RPS
Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

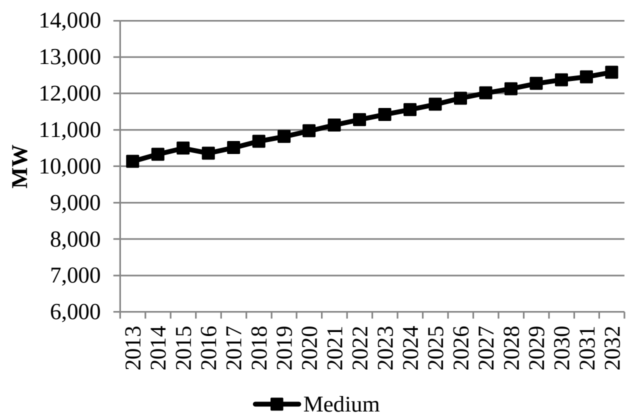
Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific
The Jim Bridger Unit 3 and Unit 4 S-4 Sensitivity will assume that if Units 3 and 4 are retired at the end of 2020 and 2021, respectively, SCR investments currently required in 2015 and 2016 can be avoided. The selection of the hypothetical retirement dates of 2020 and 2021 in this sensitivity is informed by an evaluation of the cost per ton of pollutant removed. In the case of Jim Bridger Units 3 and 4, the cost per ton of pollutant removed does not exceed a value that would likely be deemed excessive by EPA until the outer most years of unit operation. As such, a second criterion limiting the hypothetically negotiable compliance delay window to 5-years beyond the current compliance deadline is applied.

The Cholla 4 S-4 Sensitivity will assume that the unit is retired at the end of 2023 and that the SCR investment required in 2017 can be avoided. Again, the selection of the hypothetical retirement date of 2023 in this sensitivity is informed by an evaluation of the cost per ton of pollutant removed. In this case, the cost per ton of pollutant removed begins an upward trend in 2023 that that hypothetically could be deemed excessive by EPA. As such, a second criterion limiting the hypothetically negotiable compliance delay window to 5-years beyond the current compliance deadline is not applied.

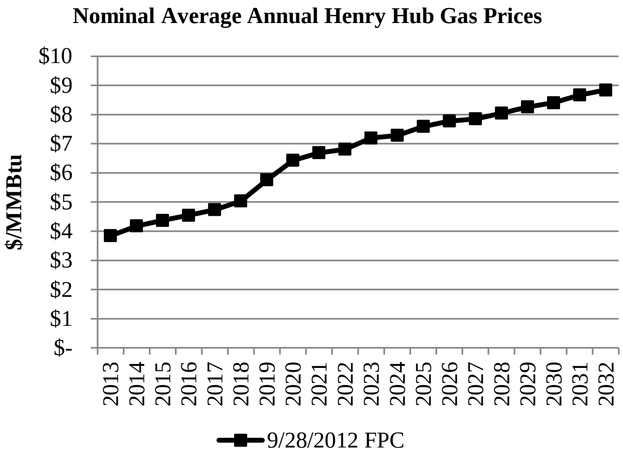
Theme: Environmental Policy Sensitivities
Sensitivity: S-X (Emissions Control PVRR(d) Analysis)

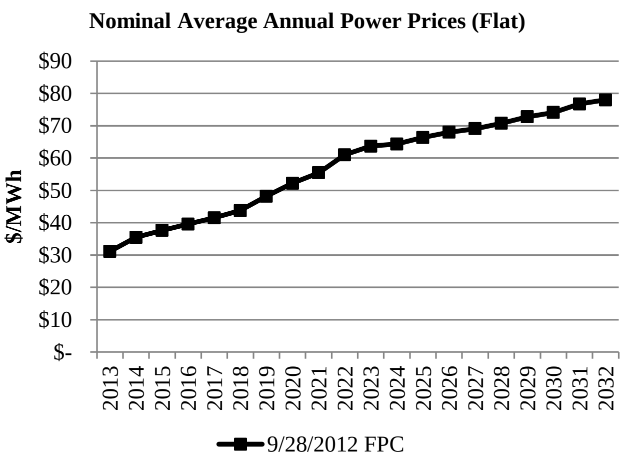
Description

Sensitivity S-X will be used to report the present value revenue requirement differential (PVRR(d)) associated with near-term emissions control investments. The PVRR(d) sensitivities will focus on near-term emissions control investments required at Hunter 1 (baghouse & low NO_X burners), Jim Bridger Units 3&4 (SCRs) and at Cholla Unit 4 (SCR). This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2. The results of Sensitivity S-X will be presented in Confidential Volume 3 of the 2013 IRP.

Forward Price Curve

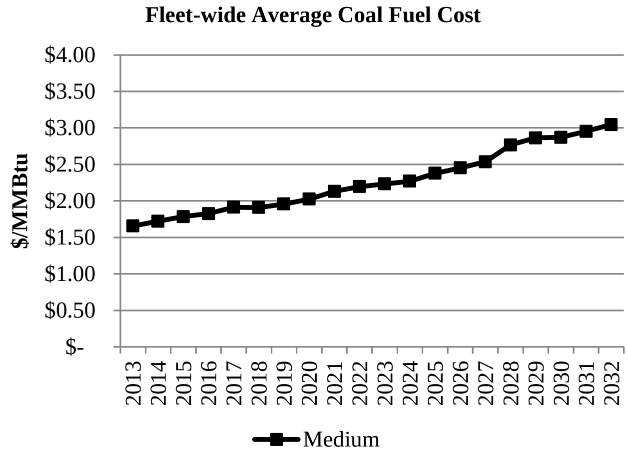
Sensitivity S-X gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





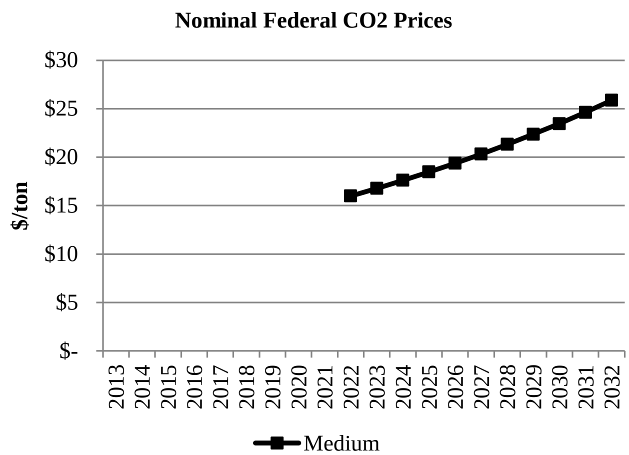
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Sensitivity S-X includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Sensitivity S-X will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Environmental Policy Sensitivities
Sensitivity: S-X (Emissions Control PVRR(d) Analysis)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-X will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-X will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

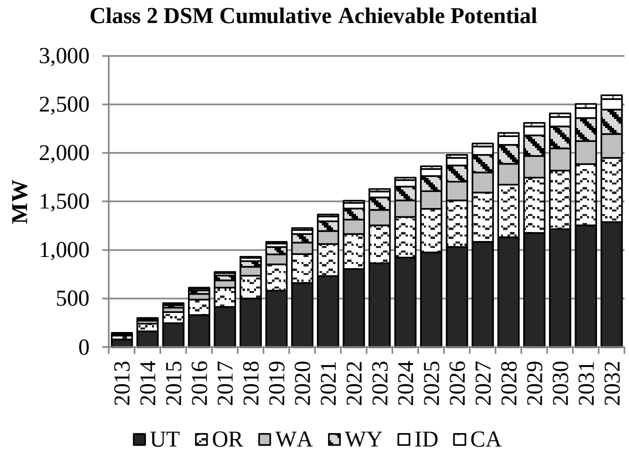
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

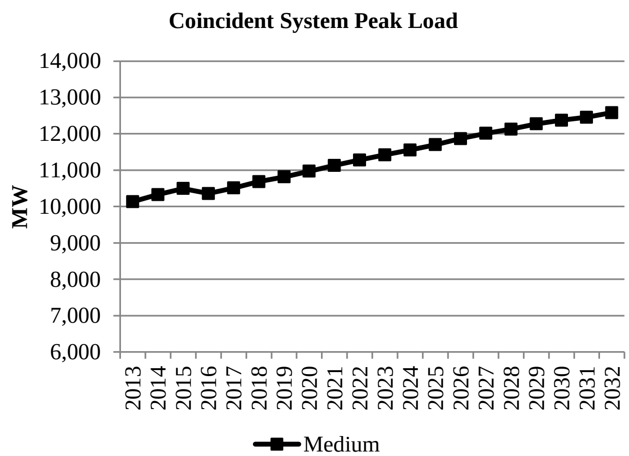
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

This sensitivity will be used to analyze the PVRR(d) of emissions control investments required at Hunter 1, Jim Bridger Units 3&4, and Cholla 4. To arrive at the PVRR(d) results, these units will be required to cease coal-fueled operation as an alternative to the required investments. The System Optimizer model will endogenously establish the prospective alternative – gas conversion or early retirement.

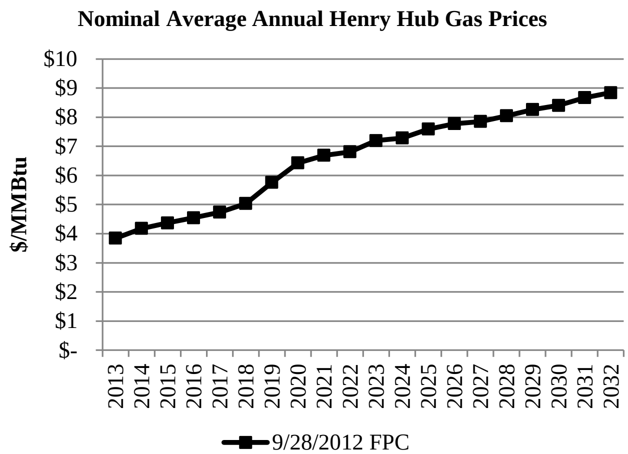
Theme: Targeted Resource Sensitivities
Sensitivity: S-5 (PTC/ITC Extension, No RPS)

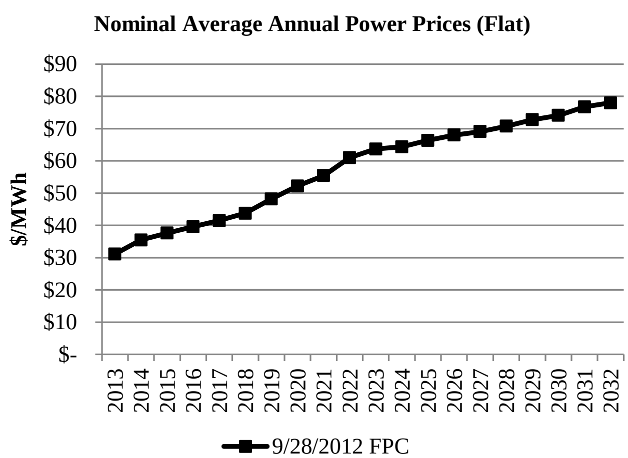
Description

Sensitivity S-5 will assume that federal tax incentives for renewable resources will be extended through 2019 and will not include any state or Federal RPS assumptions. This sensitivity is a variant of Core Case C-01 assuming Energy Gateway Scenario EG-2.

Forward Price Curve

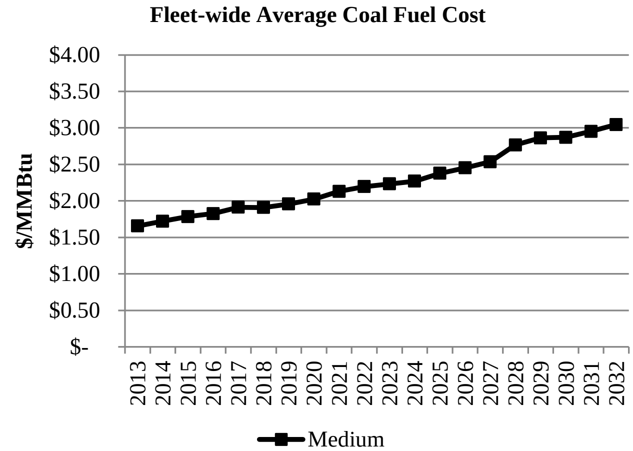
Sensitivity S-5 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





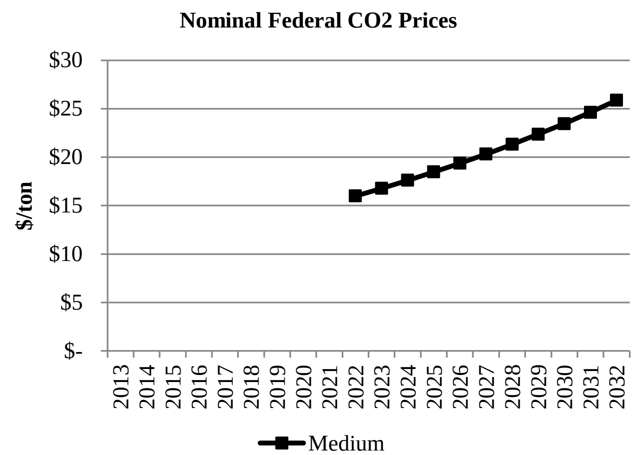
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Sensitivity S-5 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Sensitivity S-5 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Targeted Resource Sensitivities
Sensitivity: S-5 (PTC/ITC Extension, No RPS)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions
Sensitivity S-5 will include estimated costs to achieve compliance with the following:
- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

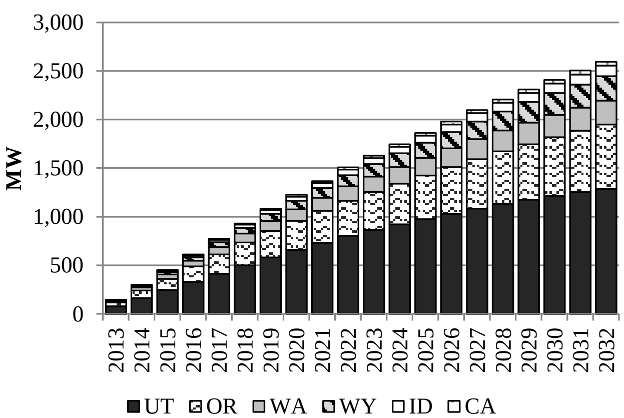
Federal RPS
Sensitivity S-5 does not include any federal RPS requirements.

State RPS
Sensitivity S-5 does not include any state RPS requirements.

Federal Tax Incentives
- PTCs extended through 2019
- ITCs extended through 2019

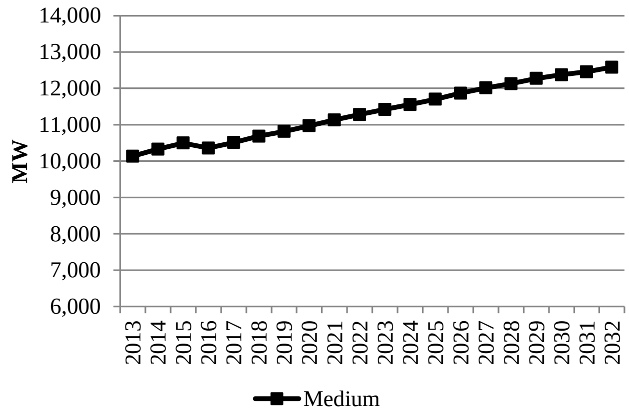
Energy Efficiency (Class 2 DSM)
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.

Class 2 DSM Cumulative Achievable Potential



Load Forecast
The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.

Coincident System Peak Load



Resource Specific
There are no other specific resource constraints that will be applied to this sensitivity.

Theme: Targeted Resource Sensitivities
Sensitivity: S-6 (PTC/ITC Extension, With RPS)

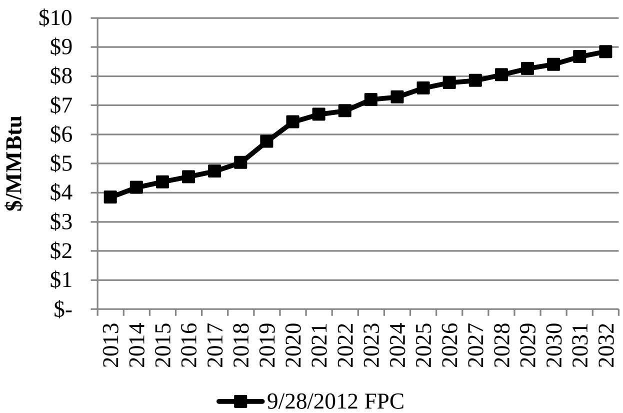
Description

Sensitivity S-6 will assume that federal tax incentives for renewable resources will be extended through 2019 and will include known state and prospective Federal RPS assumptions. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

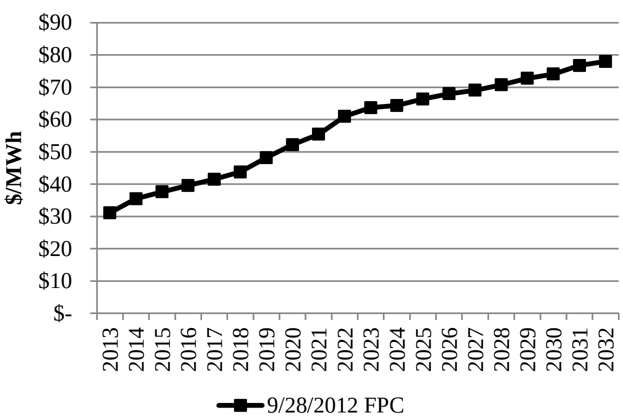
Forward Price Curve

Sensitivity S-6 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

Nominal Average Annual Henry Hub Gas Prices



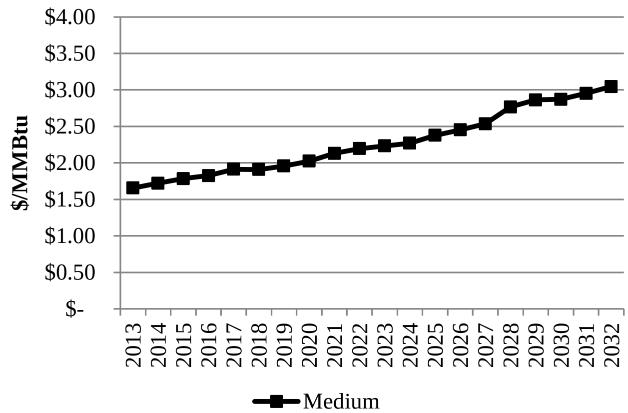
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

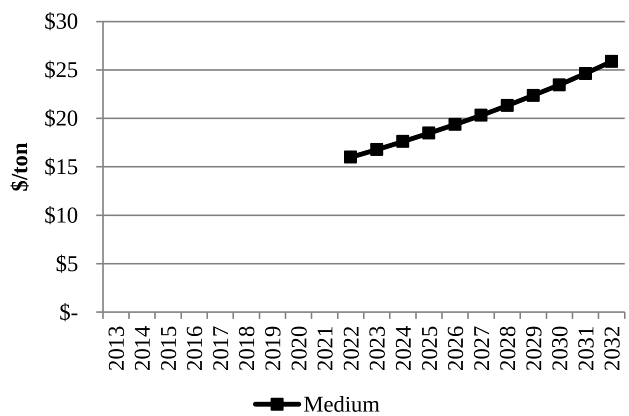
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Sensitivity S-6 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.

Nominal Federal CO2 Prices



Regional Haze

Sensitivity S-6 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Targeted Resource Sensitivities
Sensitivity: S-6 (PTC/ITC Extension, With RPS)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-6 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-6 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

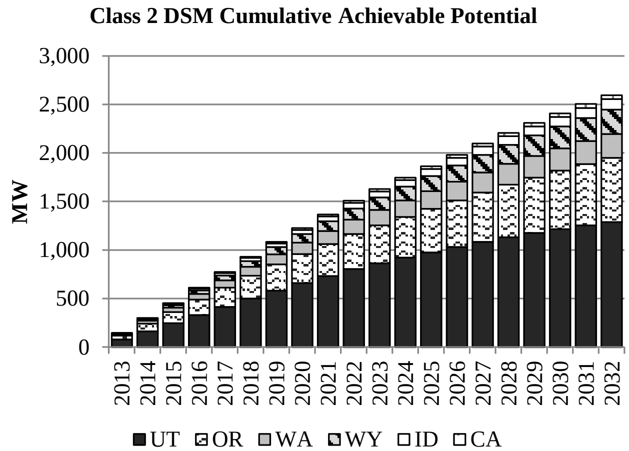
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs extended through 2019
- ITCs extended through 2019

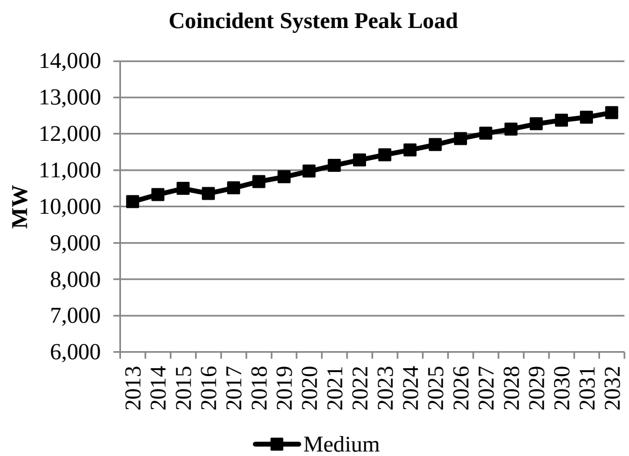
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this sensitivity.

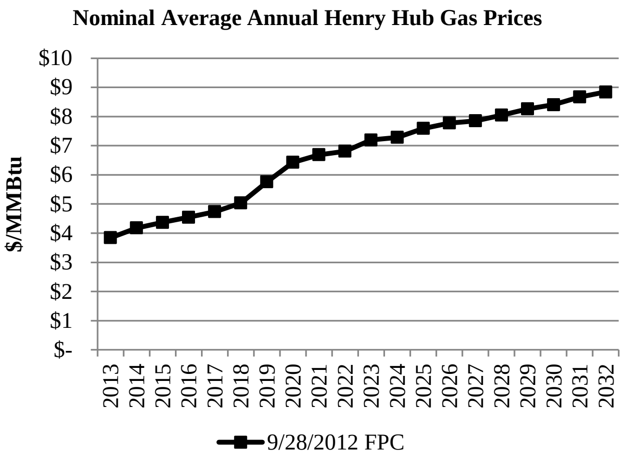
Theme: Targeted Resource Sensitivities
Sensitivity: S-7 (Endogenous RPS Compliance)

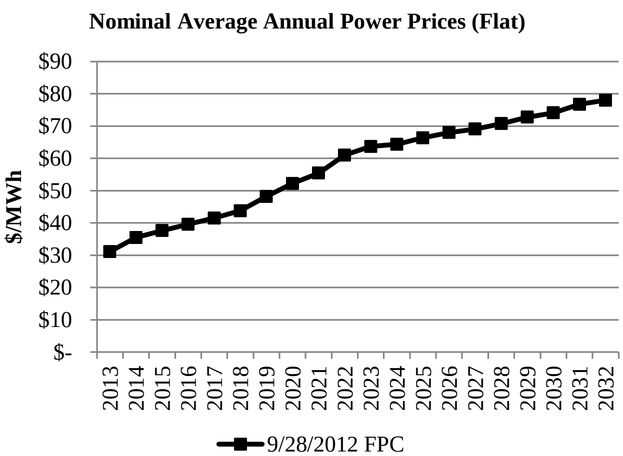
Description

Sensitivity S-7 will be completed using the RPS compliance logic built into the System Optimizer model. System level RPS requirements will be used as inputs and renewable resources will be added endogenously by the System Optimizer model. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

Forward Price Curve

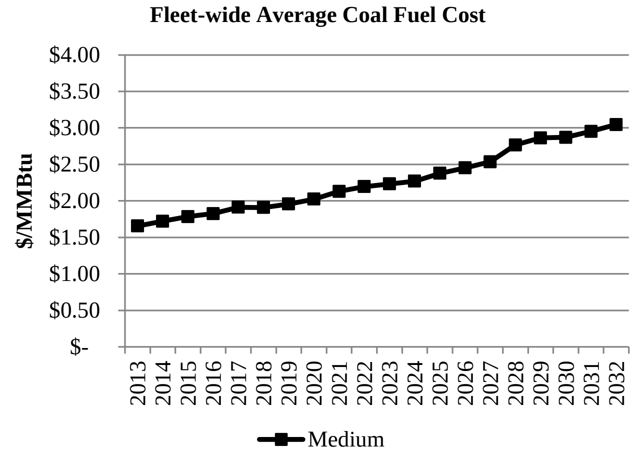
Sensitivity S-7 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





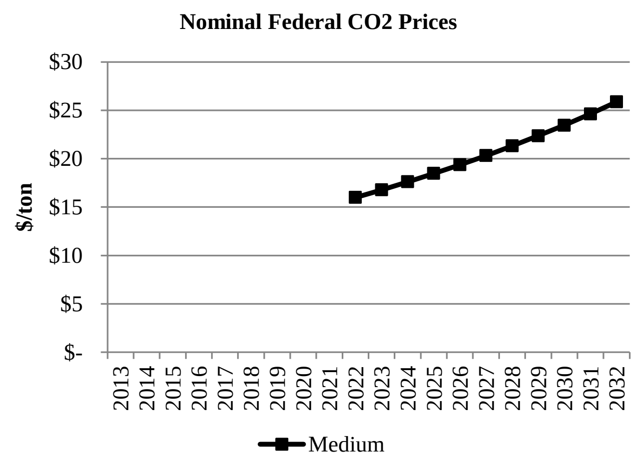
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Sensitivity S-7 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Sensitivity S-7 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-7 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-7 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

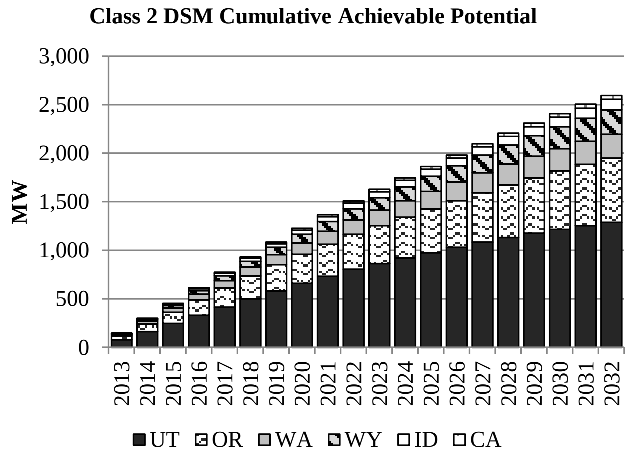
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

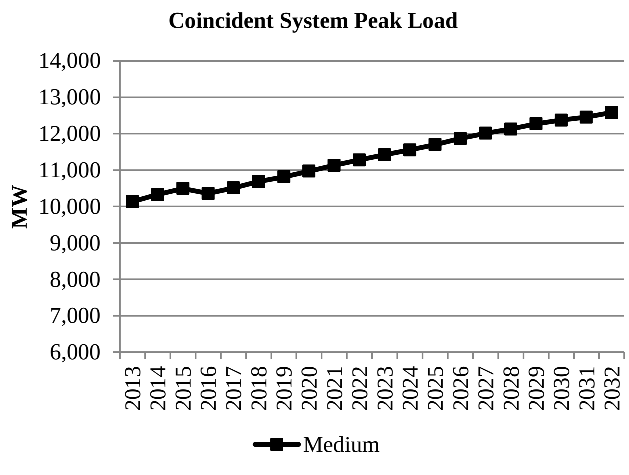
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

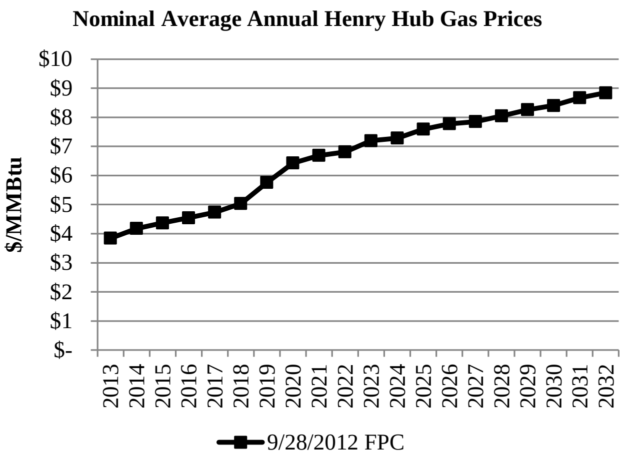
Theme: Targeted Resource Sensitivities
Sensitivity: S-8 (2013 Business Plan)

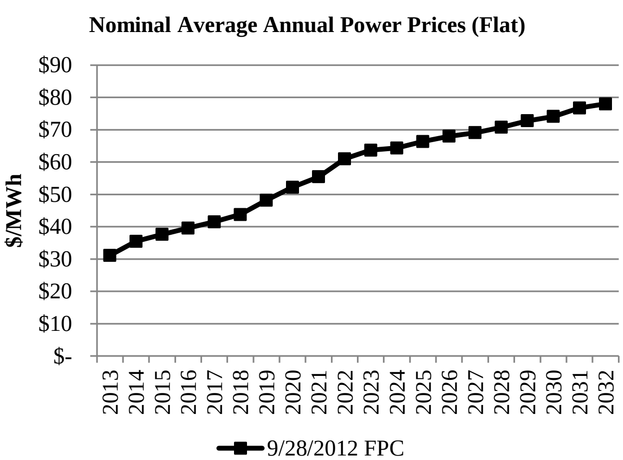
Description

Sensitivity S-8 will be completed with the resource portfolio from the Company's 2013 business plan and DSM resources re-optimized. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

Forward Price Curve

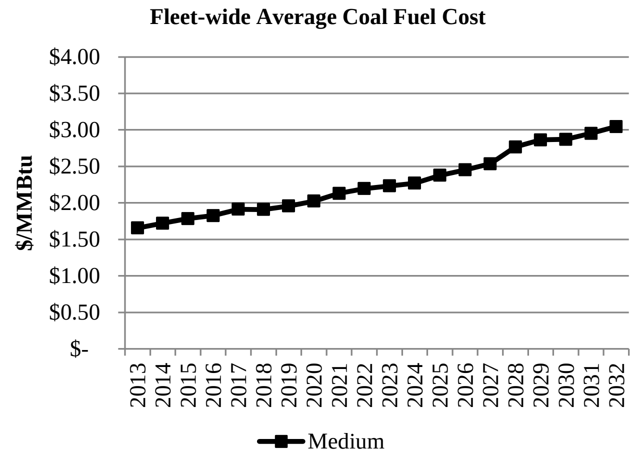
Sensitivity S-8 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.





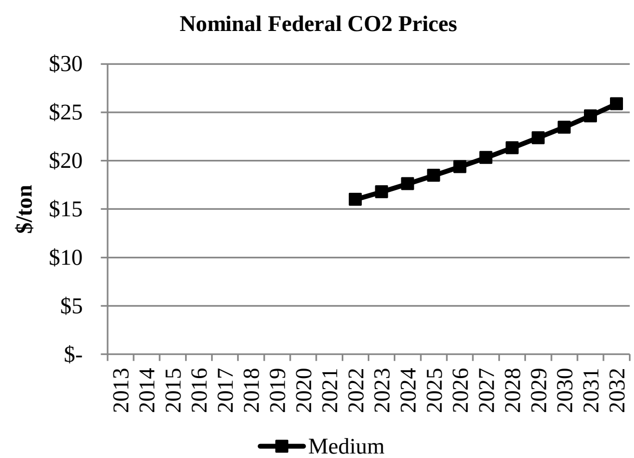
Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal

Sensitivity S-8 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze

Sensitivity S-8 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-8 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-8 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

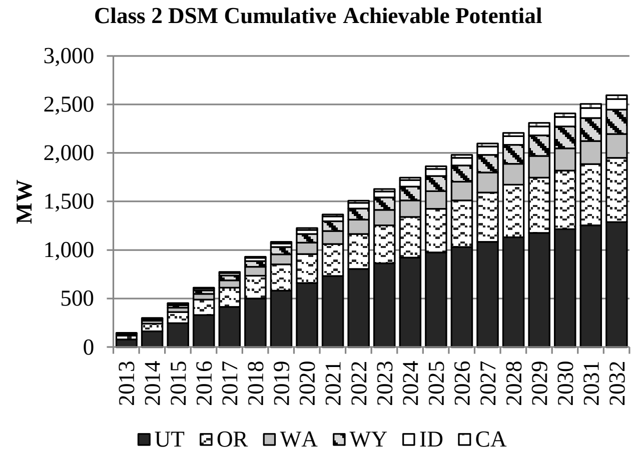
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

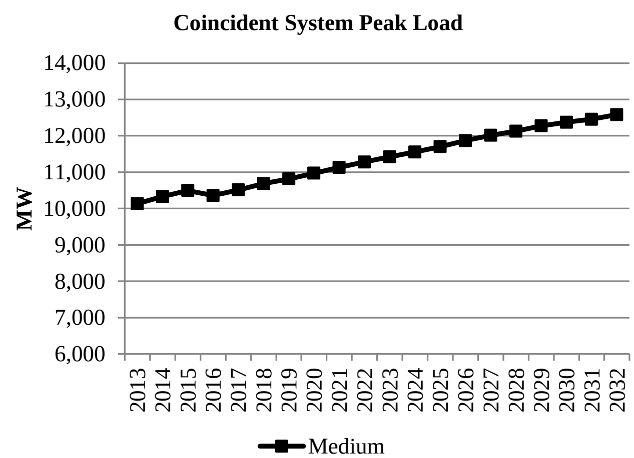
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

The resource expansion plan included in the 2013 Business Plan will be forced and DSM resources re-optimized.

Theme: Targeted Resource Sensitivities
Sensitivity: S-9 (Targeted Renewable Resources)

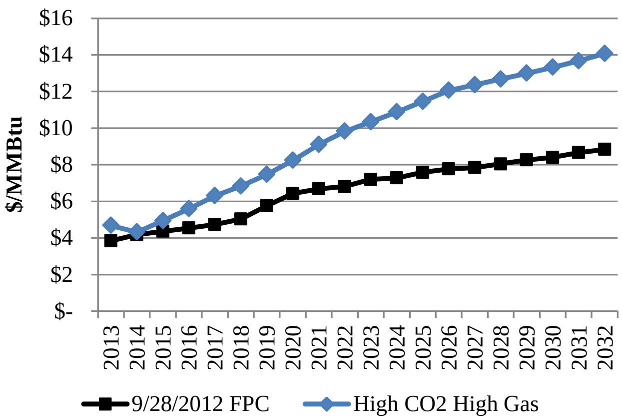
Description

Sensitivity S-9 will include market price assumptions (high gas, high CO_2) and federal tax incentive assumptions (extension of PTCs/ITCs) favorable to renewable resource additions. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

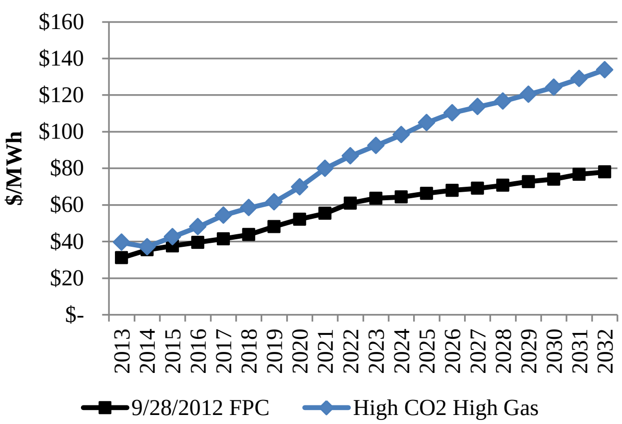
Forward Price Curve

Sensitivity S-9 gas and power prices are summarized alongside the medium case September 2012 forward price curve in the figures below.

Nominal Average Annual Henry Hub Gas Prices



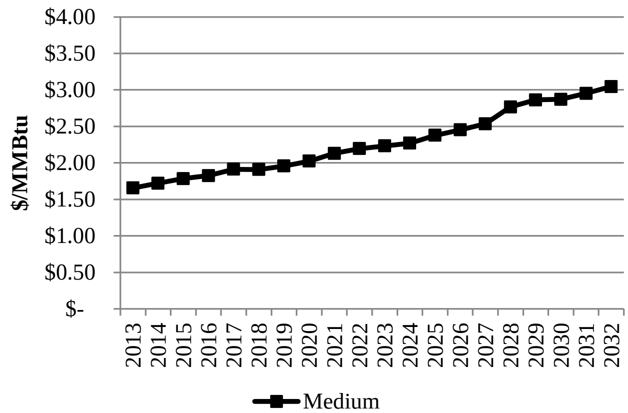
Nominal Average Annual Power Prices (Flat)



Coal Fuel Costs

Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.

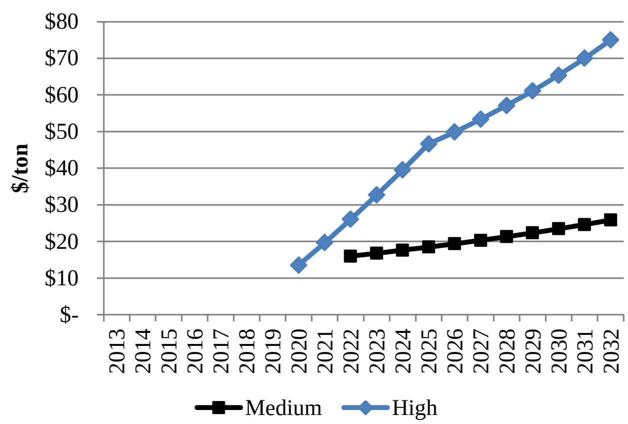
Fleet-wide Average Coal Fuel Cost



Federal CO_2 Policy/Price Signal

Sensitivity S-9 includes high CO_2 prices starting 2020 at approximately $14/ton rising to approximately $75/ton by 2032. The high CO_2 prices are shown alongside the medium CO_2 price assumptions in the figure below.

Nominal Federal CO2 Prices



Regional Haze

Sensitivity S-9 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016

Theme: Targeted Resource Sensitivities
Sensitivity: S-9 (Targeted Renewable Resources)

Cholla 4	AZ	SCR	2017

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-9 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-9 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

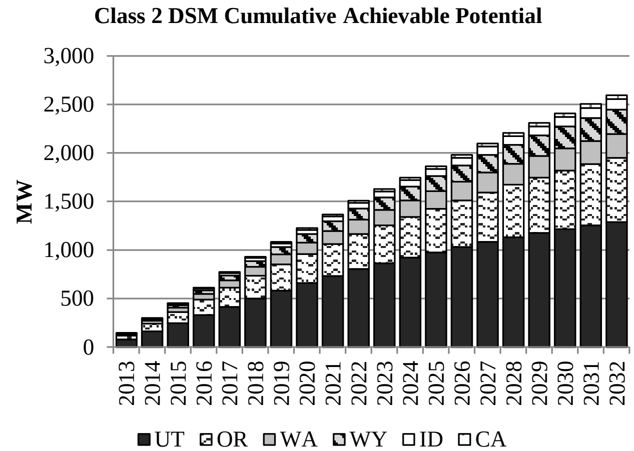
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs extended through 2019
- ITCs extended through 2019

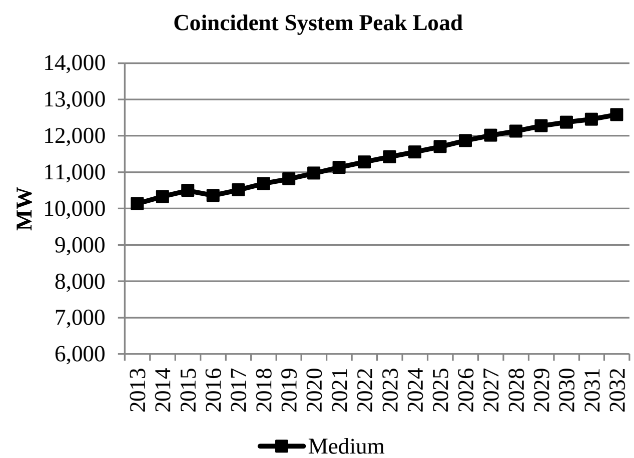
Energy Efficiency (Class 2 DSM)

Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



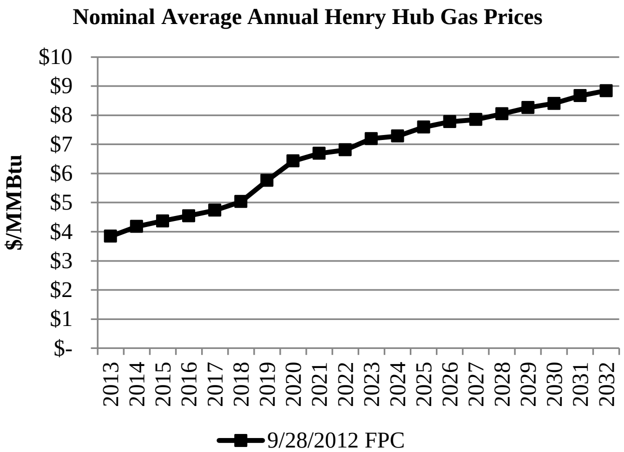
Resource Specific

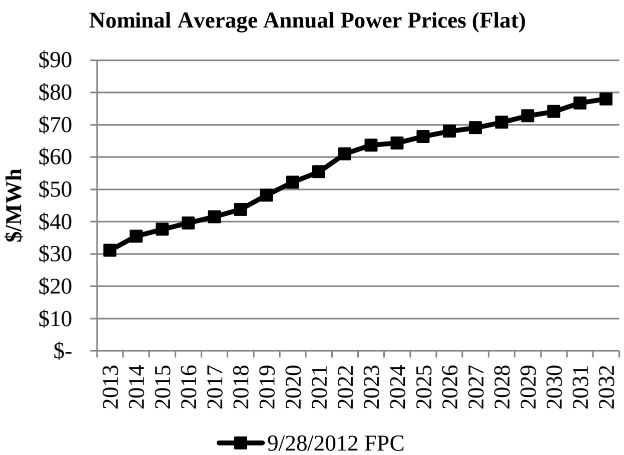
There are no other specific resource constraints that will be applied to this case.

Theme: Targeted Resource Sensitivities
Sensitivity: S-10 (Class 3 DSM)

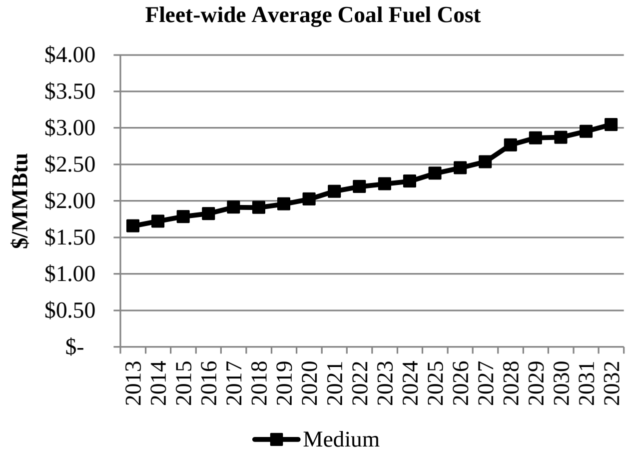
Description
Sensitivity S-10 will include Class 3 DSM resource alternatives. This sensitivity is a variant of Core Case C-03 assuming Energy Gateway Scenario EG-2.

Forward Price Curve
Sensitivity S-10 gas and power prices will utilize medium natural gas and CO_2 price assumptions consistent with the Company's September 28, 2012 official forward price curve.

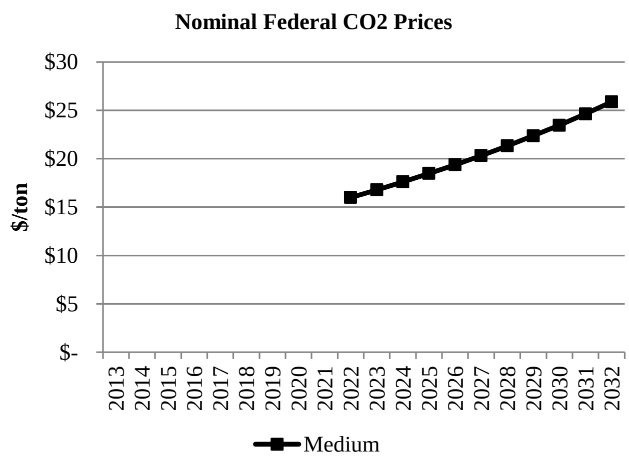




Coal Fuel Costs
Medium coal prices will be used. The figure below shows the medium fleet-wide average coal costs.



Federal CO_2 Policy/Price Signal
Sensitivity S-10 includes medium CO_2 prices starting 2022 at $16/ton rising to approximately $26/ton by 2032.



Regional Haze
Sensitivity S-10 will apply base case Regional Haze investments patterned after known state implementation plan requirements and potential long-term requirements.

Coal Unit	State	Technology*	Year
J. Bridger 1	WY	SCR	2022
J. Bridger 2	WY	SCR	2021
J. Bridger 3	WY	SCR	2015
J. Bridger 4	WY	SCR	2016
Hunter 1	UT	BH, LNB	2014
Hunter 2	UT	SCR	2023
Hunter 3	UT	SCR	2024
Huntington 1	UT	SCR	2026
Huntington 2	UT	SCR	2023
Hayden 1	CO	SCR	2015
Hayden 2	CO	SCR	2016
Craig 1	CO	SNCR	2017
Craig 2	CO	SCR	2016
Cholla 4	AZ	SCR	2017

Theme: Targeted Resource Sensitivities
Sensitivity: S-10 (Class 3 DSM)

*SNCR = selective non-catalytic reduction; SCR = selective catalytic reduction; LNB = low NOx burner; BH = baghouse

Other Non-CO_2 Environmental Policy Assumptions

Sensitivity S-10 will include estimated costs to achieve compliance with the following:

- Mercury and Air Toxics (MATS)
- Coal Combustion Residuals (CCR) under subtitle D of RCRA
- Cooling water intake structures under §316(b) of the Clean Water Act

Federal RPS

Sensitivity S-10 will include the following federal RPS assumptions:

- Targets applied to retail sales (adjusted for non-qualifying hydro)
- 4.5% in 2018
- 7.1% in 2019 – 2020
- 9.8% in 2021 – 2022
- 12.4% in 2023 – 2024
- 15% by 2025

State RPS

Known state RPS requirements with targets as a percentage of retail sales (by year-end but for WA, which is Jan 1st):

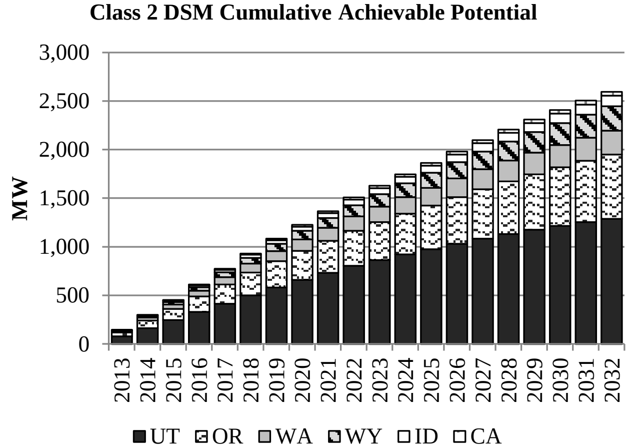
- CA: 20% through 2013, 25% by 2016, 33% by 2020
- OR: 5% by 2011; 15% by 2015; 20% by 2020, 25% by 2025
- WA: 3% by 2012; 9% by 2016; 15% by 2020
- UT: 20% of adjusted retail sales by 2025

Federal Tax Incentives

- PTCs expire end of 2012
- ITCs expire end of 2016

Energy Efficiency (Class 2 and Class 3 DSM)

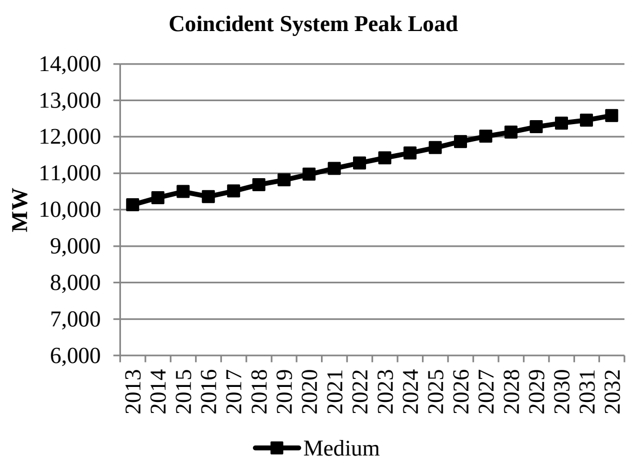
Base case supply curves and ramp rates with resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable Class 2 DSM potential by state and year are summarized below.



For this sensitivity, Class 3 DSM resources, which are generally considered non-firm due to the voluntary nature of customer response to price signals, will be considered firm resources. Only incremental potential is included in this sensitivity. To avoid overstating the capacity contribution of Class 3 DSM resources in this sensitivity, the potential for each Class 3 DSM product was adjusted for expected interactions among competing Class 1 and 3 DSM resource alternatives.

Load Forecast

The medium load forecast will be used. The figure below shows the system coincident peak load forecast before accounting for any potential contribution from DSM or distributed generation resources.



Resource Specific

There are no other specific resource constraints that will be applied to this case.

APPENDIX N – CLASS 2 DSM DECREMENT STUDY

This section presents the methodology and results of the energy efficiency (Class 2 demand-side management (DSM)) decrement study. For this analysis, the 2013 IRP preferred portfolio (Case C-07a under Energy Gateway scenario 2) was used to calculate the decrement value ("avoided cost") of various types of Class 2 DSM resources. To minimize the impacts of IRP specific assumptions when evaluating long-term resources, such as Class 2 DSM, PacifiCorp will use the 20-year levelized Class 2 DSM avoided costs shown in Table N.1 when evaluating the cost-effectiveness of current programs and potential new programs between IRP cycles.

To align with the resource costs applied for resource portfolio development using the System Optimizer capacity expansion model, cost credits were applied to the Class 2 DSM avoided cost values reflecting (1) a transmission and distribution (T&D) investment deferral benefit, (2) a generation capacity investment deferral benefit, and (3) a stochastic risk reduction benefit associated with clean, no-fuel resources.

Modeling Approach

To determine the Class 2 DSM avoided cost values, PacifiCorp defined 17 shaped Class 2 DSM resources, each at 100 megawatts maximum capacity, and available starting in 2013 and for the duration of the 20-year IRP study period.

Consistent with prior valuation studies, PacifiCorp first determined the system production cost with and without each Class 2 DSM resources using the Planning and Risk production cost model in Monte Carlo stochastic mode. The difference in production cost (stochastic mean present value revenue requirement (PVRR)) for the two runs indicates the system value attributable to the DSM resource through lower spot market transaction activity and resource re-optimization with the DSM resource in the portfolio. The cost credits mentioned above are then added separately outside of the model, thereby increasing Class 2 DSM avoided cost values. The Planning and Risk avoided cost values were determined for the medium CO_2 tax scenario (starting at $16/ton in 2022 and escalating to $26/ton by 2032).

Generation Resource Capacity Deferral Benefit Methodology

PacifiCorp used the System Optimizer model to determine the generation resource capacity deferral benefit. The approach is similar to the stochastic production cost difference method, except that only the fixed cost benefit of a 100-megawatt Class 2 DSM resource is calculated. This is accomplished by running System Optimizer model with a base resource portfolio, and then comparing the fixed portfolio costs against the cost of the same portfolio derived by System Optimizer that removes 100-megawatt of DSM program. The simulation period is 20 years. As a simplifying assumption, PacifiCorp applied the East "system" load shape for the generic DSM program, which has a capacity planning contribution of 94 percent and a capacity factor of 70 percent. The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined-cycle combustion turbine (CCCT). The difference in the portfolio fixed cost represents the resource deferral benefit of the DSM program. (Note that System Optimizer's production cost benefits were not taken into account to avoid double-counting the benefit extracted from stochastic Planning and Risk model results.)

Since a 100-megawatt Class 2 DSM is not sufficiently large enough to defer a whole CCCT unit, System Optimizer was configured to allow fractional CCCT unit sizes for both the base portfolio and the Class 2 DSM resource portfolio. Deferral of CCCT capacity can begin starting in 2017. Note that each Class 2 DSM resource can also defer front office transactions (a market resource representing a range of forward firm market purchase products).

The resource capacity deferral benefit is calculated in two steps:

1. Fixed Cost Deferral Benefit Determination
   Fixed cost benefits are obtained by calculating the differences in annual fixed and capital recovery costs (millions of 2012 dollars) between the base portfolio and the portfolio with the Class 2 DSM program removed. The stream of annual benefits is then converted into a net present value (NPV) using the 2013 IRP discount rate (6.882 percent).
2. Levelized Value Calculation
   The fixed cost resource deferral benefit value obtained from step 1 is divided by the Class 2 DSM program energy in megawatt-hours (also converted to a NPV) to yield a value in dollars per megawatt-hour-year ($/MWh-year).

This value, along with the T&D investment deferral credit and stochastic risk reduction credit, are added to the Planning and Risk model decrement values to yield the final adjusted values.

Class 2 DSM Decrement Value Results

Table N.1 reports the NPV levelized avoided costs by DSM resource and CO_2 tax scenario for 2013 through 2032, along with a breakdown of the three cost credits (capacity deferral, T&D investment deferral, and stochastic risk reduction). Tables N.1 and N.2 report the levelized Avoided Cost and the annual nominal-dollar avoided costs, in $/MWh.

Consistent with the results for the 2011 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The water heating, plug loads, and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table N.1 – Levelized Class 2 DSM Avoided costs, 20-Year Net Present Value (2013-2032)

Resource	Location	Load Factor	Cost Credit Components ($/MWh)				Total Avoided Costs Including all Cost Credits ($/MWh)
			Capacity Resource Deferral	T&D Investment Deferral	Stochastic Risk Reduction	Total Credits	
Residential Cooling	East	10%	18.49	64.61	2.10	85.20	146.13
Residential Lighting	East	48%	18.49	12.85	2.52	33.87	80.86
Residential Whole House	East	35%	18.49	17.71	2.40	38.61	87.28
Commercial Cooling	East	20%	18.49	10.45	2.67	31.62	107.94
Commercial Lighting	East	48%	18.49	10.80	2.52	31.81	84.05
Water Heating	East	57%	18.49	31.95	2.44	52.87	79.18
Plug Loads	East	59%	18.49	12.76	2.74	33.99	77.48
System Load Shape	East	70%	18.49	8.88	2.62	29.99	75.75
Residential Cooling	West	7%	18.49	90.98	1.39	110.86	161.83
Residential Heating	West	25%	18.49	26.17	2.27	46.93	88.87
Residential Lighting	West	48%	18.49	12.85	2.81	34.15	77.85
Commercial Cooling	West	16%	18.49	12.93	2.81	34.23	106.58
Residential Whole House	West	49%	18.49	10.45	2.90	31.85	77.89
Commercial Lighting	West	48%	18.49	10.89	2.77	32.14	79.67
Water Heating	West	56%	18.49	37.75	2.24	58.48	75.70
Plug Loads	West	59%	18.49	12.76	2.72	33.98	74.88
System Load Shape	West	71%	18.49	8.61	2.85	29.96	73.03

Table N.2 – Annual Nominal Class 2 DSM Avoided Costs, 2013-2032

Decrement Name	Actual Load Factor	Decrement Values (Nominal $/MWh)									
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EAST											
Residential Cooling	10%	118.51	118.95	123.98	131.72	153.60	121.70	144.87	140.44	128.53	171.08
Residential Lighting	48%	61.07	61.94	65.21	67.69	73.25	68.16	74.44	75.95	76.10	97.40
Residential Whole House	35%	66.21	67.40	71.01	73.51	80.03	73.14	81.81	82.80	80.60	106.52
Commercial Cooling	20%	82.92	84.76	88.64	92.74	104.68	89.66	103.14	103.01	97.71	132.00
Commercial Lighting	48%	61.66	63.53	66.62	69.31	74.53	70.43	77.96	77.89	78.63	103.10
Water Heating	57%	58.52	59.86	63.02	65.23	69.54	66.59	72.44	73.62	75.12	95.20
Plug Loads	59%	57.95	58.83	61.99	64.36	68.90	65.49	70.43	72.99	73.85	93.66
System Load Shape	70%	56.24	57.43	60.14	62.72	66.07	64.43	68.76	70.74	72.87	91.36
WEST											
Residential Cooling	7%	144.28	145.27	146.33	157.79	183.68	138.01	158.82	158.57	138.83	179.04
Residential Heating	25%	71.93	73.72	74.07	79.70	86.16	75.95	82.91	84.86	80.77	105.58
Residential Lighting	48%	60.57	61.87	63.50	66.90	71.78	66.74	71.48	73.44	73.51	91.95
Commercial Cooling	16%	88.92	89.67	91.53	97.59	109.02	90.80	101.81	102.90	96.11	120.75
Residential Whole House	49%	60.48	61.94	63.69	66.68	70.90	66.83	71.45	73.67	73.65	91.98
Commercial Lighting	48%	61.52	62.74	65.23	68.30	72.70	68.05	73.29	74.71	75.66	93.80
Water Heating	56%	58.20	59.55	61.46	64.49	68.32	64.84	69.31	71.20	72.46	88.33
Plug Loads	59%	57.77	59.19	60.56	63.71	67.36	63.87	67.89	70.46	71.35	88.84
System Load Shape	71%	55.97	57.38	58.93	61.86	64.57	62.29	65.87	68.35	70.12	86.38

Table N.2 – Annual Nominal Class 2 DSM Avoided Costs, 2013-2032 (Continued)

Decrement Name	Decrement Values (Nominal $/MWh)									
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EAST										
Residential Cooling	167.70	168.33	135.41	190.10	252.77	122.82	136.44	138.04	214.18	194.54
Residential Lighting	95.45	95.07	90.75	100.99	118.72	94.52	96.75	97.63	115.94	114.01
Residential Whole House	104.14	103.88	93.86	110.84	132.59	96.77	100.67	101.57	122.92	122.04
Commercial Cooling	124.62	125.67	113.18	135.87	176.68	107.72	119.99	116.78	157.09	145.85
Commercial Lighting	101.32	99.45	95.76	107.06	126.40	99.50	103.68	104.19	118.12	117.59
Water Heating	96.07	93.27	91.24	100.01	117.34	93.01	98.55	98.78	112.99	112.25
Plug Loads	93.13	90.17	86.05	97.27	114.19	93.20	93.08	95.05	112.32	109.66
System Load Shape	92.27	87.28	86.73	94.23	108.78	92.30	95.02	94.67	108.43	107.77
WEST										
Residential Cooling	153.86	183.13	143.24	199.23	264.43	109.03	131.61	142.59	240.98	220.96
Residential Heating	95.03	102.49	90.99	113.32	133.74	88.00	91.54	96.49	130.63	126.66
Residential Lighting	86.31	89.69	85.36	97.05	108.04	87.41	92.77	95.81	114.49	110.90
Commercial Cooling	110.18	122.28	106.86	129.57	162.76	94.22	109.41	114.91	156.95	148.11
Residential Whole House	86.20	90.12	85.75	97.66	108.08	88.08	93.75	96.10	113.21	110.81
Commercial Lighting	87.97	92.45	88.70	99.85	110.92	89.26	97.45	100.19	114.85	113.08
Water Heating	84.52	87.63	84.54	95.26	103.60	87.26	93.52	95.84	109.64	108.07
Plug Loads	84.09	87.33	82.89	94.45	102.92	85.96	91.92	93.43	109.16	106.98
System Load Shape	82.20	84.77	82.83	92.30	98.72	86.28	92.28	92.93	105.22	104.44

APPENDIX O – WIND AND SOLAR PEAK CONTRIBUTION

Overview

The amount of capacity provided by a resource at the time of system peak is known as its peak capacity contribution, which is stated as a percentage of its nameplate capacity. The Company calculated wind peak contribution by analyzing the historical generation over the Company's 100 summer peak load hours in each of four historical years and assuming a 90 percent probability that the resource will produce at least that same level of power during peak hours in the future. The solar peak contribution was determined based on third party information due to lack of historical data from the Company's system. The peak contributions of the resources using historic data are presented in Table O.1.

Table O.1 – Wind and Solar Peak Contribution (% of nameplate capacity)

Resource	Peak Contribution
Wind	4.2%
Solar	13.6%

Methodology

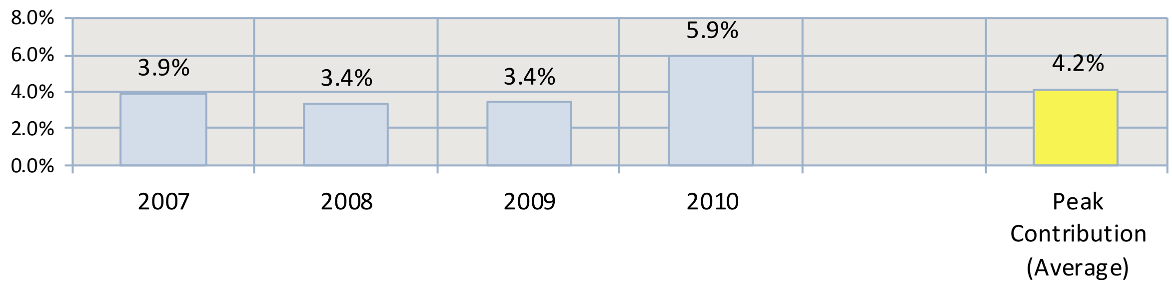
For both the wind and solar resources, the peak contributions are based on historical generation, if available, provided by a particular resource type in the top 100 summer peak load hours assuming a 90 percent probability that it will produce the same level of power during peak hours in the future. The historical data are from a four year period from 2007 to 2010. The average of the four annual values represents the peak contribution for that resource type. The period of measure is restricted to summer load hours since the Company's system peak occurs in the summer months. Detailed steps of the calculations are:

- Compile the aggregate energy output from all resources of the resource type in each hour of the year;
- Calculate the aggregate nameplate capacity from all resources of each type in each hour of the year;
- Divide the aggregate energy output by the aggregate nameplate capacity to arrive at the aggregate capacity factor for each hour of the year;
- Using actual hourly system load data for 2007-2010 to determine the top 100 load hours that occurred in each year between the months of June and September. The resulting hours are the top 100 summer peak load hours for each year 2007-2010;
- Align the hourly aggregate generation of the resource set to the top 100 summer peak load hours in each year; and
- Calculate the capacity contribution based on a 90 percent probability from the level of generation of the resource set during those peak hours.

Wind

The Company determined that the historic wind generation had a peak contribution of 4.2 percent. This value is comparable to the five percent wind capacity contribution assumption used by the Northwest Power and Conservation Council.[65] Hourly generation logs were used to develop the capacity contribution for the Company's system wind resources. The analysis included owned resources and non-owned wind resources where the Company acquired the output under a power purchase agreement. Figure O.1 shows the result of the study, and Table O.2 lists the wind generation resources that were included in the study.

Figure O.1 – Wind Peak Contribution, in top 100 summer load hours



[65] Sixth Northwest Conservation and Electric Power Plan, N.W.P.C.C. Chapter 12, 4, http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Ch12.pdf .

Table O.2 – Resources Included in the Wind Analysis

Wind Resource	COD	Type	Nameplate Capacity
Chevron Wind QF	12/1/2009	PPA	16.5
Combine Hills	12/22/2003	PPA	41.0
Dunlap I Wind	10/1/2010	Owned	111.0
Foote Creek Generation	7/21/1997	Owned	32.1
Glenrock III Wind	1/17/2009	Owned	39.0
Glenrock Wind	12/31/2008	Owned	99.0
Goodnoe Wind	5/31/2008	Owned	94.0
High Plains Wind	9/13/2009	Owned	99.0
Leaning Juniper 1	9/14/2006	Owned	100.5
Marengo 1 & 2	8/3/2007	Owned	210.6
McFadden Ridge Wind	9/29/2009	Owned	28.5
Mountain Wind 1 & 2 QF	7/2/2008	PPA	140.7
Oregon Wind Farm QF	3/31/2009	PPA	64.6
Rock River I	11/7/2001	PPA	50.0
Rolling Hills Wind	1/17/2009	Owned	99.0
Seven Mile II Wind	12/31/2008	Owned	19.5
Seven Mile Wind	12/31/2008	Owned	99.0
Spanish Fork Wind 2 QF	7/31/2008	PPA	18.9
Three Buttes Wind	12/1/2009	PPA	99.0
Threemile Canyon Wind QF p500139	9/1/2009	PPA	9.9
Top of the World Wind p522807	10/1/2010	PPA	200.2
Wolverine Creek	2/12/2006	PPA	64.5
	Total Wind December 31, 2010:		**1,736.5**

Solar

The Company did not have sufficient historical data from operating solar resources during 2007 – 2010 from which it could develop the capacity contribution value for a solar QF. In the absence of actual system data, the Company relied on a simulated hourly solar profile developed by the National Renewable Energy Laboratory (NREL). The identical simulated hourly data is compared against the top 100 summer load hours in each year 2007 – 2010. Unlike wind, where the levels of generation change in each year depending on the output of the resource set, the simulated solar output remains constant in each year and is compared to changes in the top 100 peak summer load hours from year to year.

In developing the solar generation profile the Company used an NREL tool, called PVWatts, in order to simulate hourly solar generation levels based on historic meteorological solar radiation data. The PVWatts tool develops a solar profile based on input parameters such as the location, size, array type, tilt angle, and azimuth angle of the solar resource.

The peak contribution calculation was based on a simulated group of solar resources located throughout the Company's service territory. It was developed using the combined simulated profiles from five locations: Pocatello, ID; Yakima, WA; Pendleton, OR; Lander, WY; and Salt Lake City, UT. The analysis was performed twice, first with all of the resources configured to peak and second with all of the resourced configured to energy, as detailed above. Figure O.2 shows the result of the study

Figure O.2 – Solar Resource Peak Contribution, in top 100 summer load hours