PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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March 31, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Drive SE
Salem, Oregon 97302-1166

Attn: Filing Center

RE: Docket No. LC 57
PacifiCorp's 2013 Integrated Resource Plan Update

Please find enclosed an original and five copies of PacifiCorp d/b/a Pacific Power's (PacifiCorp or Company) 2013 Integrated Resource Plan (IRP) Update (2013 IRP Update). The 2013 IRP Update is also available electronically on PacifiCorp's IRP website, at http://www.pacificorp.com/es/irp.html. The Company's 2013 IRP was filed with the Public Utility Commission of Oregon on April 30, 2013.

The 2013 IRP Update describes resource planning and procurement activities that occurred subsequent to the filing of the 2013 IRP, presents an updated resource needs assessment, an updated resource portfolio consistent with changes in the planning environment, and provides an IRP Action Plan status update. The 2013 IRP Update is being submitted for informational purposes only and the Company does not request acknowledgment of its 2013 IRP Update. The confidential version is provided subject to Protective Order No. 13-095 adopted for this proceeding. A redacted version is also provided.

It is respectfully requested that all data requests regarding this filing be addressed as follows:

By e-mail (preferred):	datarequest@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, Oregon, 97232

If there are any informal inquiries concerning this filing, please contact Ted Drennan, Manager Integrated Resource Planning at (503) 813-6841 or Gary Tawwater, Manager, Regulatory Affairs, at (503) 813-6805.

Sincerely,

R. Bryce Dalley /GWT

R. Bryce Dalley
Vice President, Regulation

cc: Service List LC 57

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's 2013 IRP Update on the parties listed below via electronic mail and/or Overnight Delivery in compliance with OAR 860-001-0180.

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Dated this 31st Day of March 2014.

Carrie Meyer
Supervisor, Regulatory Operations

2013

Integrated Resource Plan Update

REDACTED

PACIFICORP

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

March 31, 2014

Let's turn the answers on.

This 2013 Integrated Resource Plan Update 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*
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EXECUTIVE SUMMARY

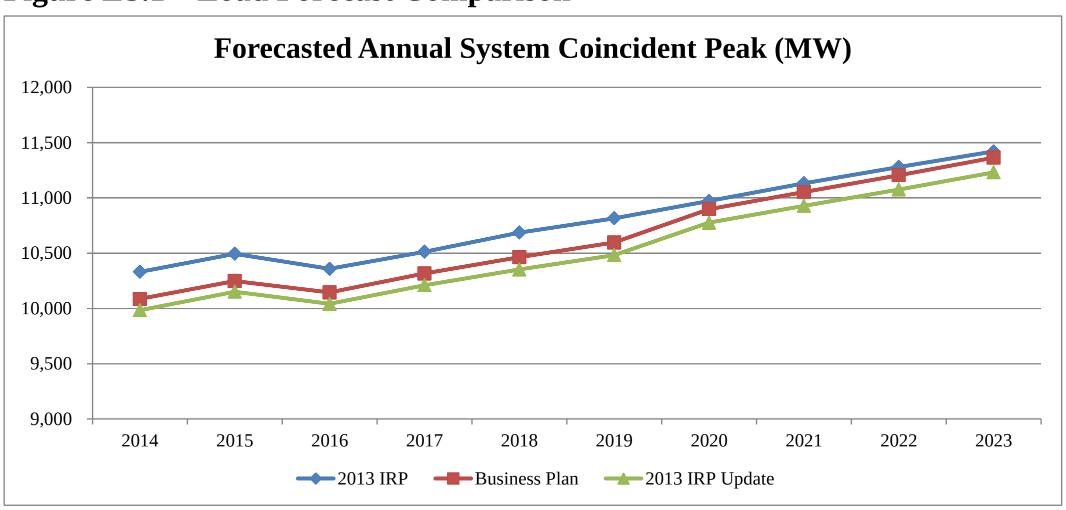
PacifiCorp submitted its 2013 Integrated Resource Plan (2013 IRP) to state regulatory commissions in April 2013. That plan provides a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks for customers. This 2013 IRP Update describes resource planning and procurement activities that occurred subsequent to the filing of the 2013 IRP, presents an updated resource needs assessment, an updated resource portfolio consistent with changes in the planning environment, and provides an IRP Action Plan status update. In presenting the updated resource needs assessment and updated resource portfolio, PacifiCorp shows changes relative to the 2013 IRP and relative to PacifiCorp's fall 2013 ten-year business plan, which covers the 2014 to 2023 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2013 IRP acknowledgement process.

2013 IRP Update Highlights

PacifiCorp's long-term planning process involves balanced consideration of cost, risk, uncertainty, supply reliability/delivery, and long-run public policy goals. The following summarizes the key highlights of PacifiCorp's 2013 IRP Update:

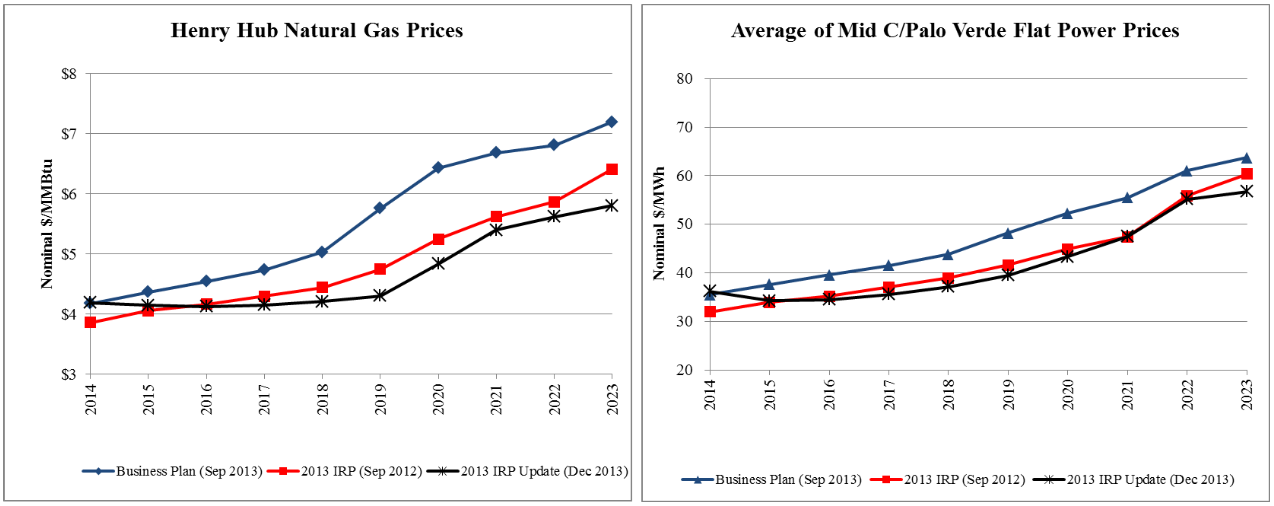
- As shown in Figure ES.1 the Company's most recent coincident system peak load forecast is down relative to the 2013 IRP, and the intervening fall 2013 ten-year business plan. The coincident peak forecast decreased through the planning period. Driving the reduction in peak load are a reduced residential class load forecast relative to the 2013 IRP due to increased energy efficiency and continued phase in of the Energy Independence and Security Act federal lighting standards. In addition, recent history has seen low growth in the peak, which in turn reduces the long-term forecast peak load growth expectations. With a reduced coincident system peak forecast, the need for new resources is pushed further out in the planning horizon as compared to the 2013 IRP. In the 2013 IRP Update resource portfolio, a new thermal resource is not needed until 2027.

Figure ES.1 – Load Forecast Comparison



- Figure ES.2 shows that forecast natural gas and energy prices have declined from those assumed in the 2013 IRP and the fall 2013 ten-year business plan. Domestic gas price forecasts continue to be driven down by growth in unconventional shale gas plays. This in turn (combined with lower forecast regional loads) impacts forward market power prices.

Figure ES.2 – Power and Natural Gas Price Comparisons



- With a reduced coincident system peak forecast and lower market prices, the updated resource portfolio continues to show that customer loads over the front ten years of the planning horizon will be met with front office transactions (firm market purchases) and through energy efficiency. PacifiCorp continues to pursue acceleration of cost-effective energy efficiency consistent with its 2013 IRP Action Plan.

- The Energy Gateway transmission project continues to play an important role in the Company's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Several Energy Gateway developments have occurred since the Company's 2013 IRP was filed, including reaching construction and permitting milestones, adjusting in-service dates for future segments, and developing activities on joint-development projects. Accordingly, in-service dates have been updated relative to those assumed for the 2013 IRP. These date adjustments coincide with revised permitting dates, generation facility needs and updated load growth assumptions.

- The Environmental Protection Agency (EPA) partially approved and partially rejected the Wyoming Regional Haze state implementation plan (SIP) and issued a federal implementation plan (FIP) to cover those areas of SIP disapproval in January 2014. This action established compliance requirements and schedules for specific Wyoming coal units under the Regional Haze program, including a requirement for installation of selective catalytic reduction (SCR) at Wyodak by early March 2019. For purposes of the 2013 IRP Update, the resource needs assessment and updated resource portfolio reflects the continued operation of Wyodak as a coal-fired generating asset through the planning horizon. PacifiCorp will be analyzing the Wyodak SCR investment and alternatives to this investment in its 2015 IRP.

- In EPA's action on the Wyoming SIP in January 2014, it explicitly stated its support for the natural gas conversion of Naughton Unit 3, but noted that because the Wyoming SIP documentation did not include a natural gas conversion option, EPA has no basis to disapprove the Wyoming SIP requirement for low NO_X burners/overfired air, SCR, and baghouse, with its authority and obligation to take action on the SIP as submitted by the state. PacifiCorp has since been working with the state of Wyoming Division of Air Quality to identify amendments necessary to support the Naughton Unit 3 natural gas conversion and to clearly document the compliance requirements and timeline for implementation of the project under the Regional Haze program. In the 2013 IRP Update, the resource needs assessment and updated resource portfolio continues to reflect a gas conversion completed by summer 2015.

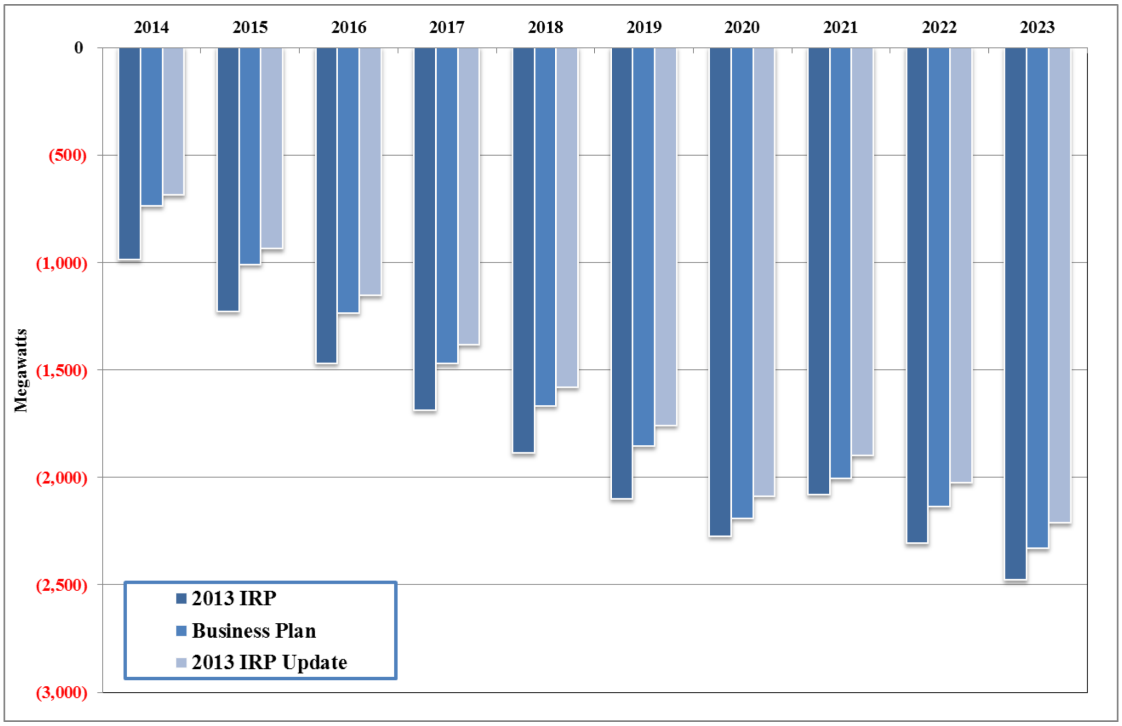
- Since 2010, no significant activity has occurred with respect to the development of a federal renewable portfolio standard (RPS). In addition, current political environments are shifting focus from items such as the extension of federal incentives for renewables and portfolio standards to EPA's development of greenhouse gas standards. Accordingly, the 2013 IRP Update assumes no federal RPS requirement over the course of the planning horizon. With the removal of the federal RPS assumptions requirements, the updated resource portfolio shows a reduced need for renewable resources required solely to meet state RPS obligations in 2024 and 2025.

- After PacifiCorp filed the 2013 IRP, President Obama issued a Presidential Memorandum in June 2013 directing EPA to issue standards, regulations, or guidelines, as appropriate that address greenhouse gas emissions from modified, reconstructed, and existing power plants. The proposed standards, regulations, or guidelines are to be issued by June 1, 2014, finalized by June 1, 2015, with implementation of regulations as proposed in SIPs required by June 30, 2016. EPA would then review the implementation plan proposed by each state, and the effective compliance dates for these standards, regulations, or guidelines would become applicable sometime thereafter. Absent information on how EPA intends to proceed with its rule-making process, and without any information on how individual states will propose to implement those regulations through a SIP, there is currently no means to develop a specific CO_2 price assumption that accurately reflects potential CO_2 regulation. PacifiCorp's review of current third-party CO_2 price forecasts shows that despite issuance of the Presidential Memorandum, these forecasters have not materially altered either their assumed CO_2 start date or price level. In the 2013 IRP Update, PacifiCorp continues to assume a CO_2 price signal beginning 2022 at $16/ton escalating at three percent plus inflation thereafter, and expects to update its CO_2 policy assumptions and scenarios in the 2015 IRP, taking into consideration the proposed standard, regulation, or guidelines expected to be issued by EPA later this year.

Resource Need Update

Figure ES.3 shows the 2013 IRP Update resource need, prior to acquiring any new resources, alongside the resource need from the 2013 IRP and the fall 2013 ten-year business plan. Overall, the forecasted need has declined with the most recent needs assessment. Primarily driven by an updated load forecast, the most recent resource needs assessment shows an average reduction in peak resource need of approximately 320 megawatts (MW) as compared to the 2013 IRP for the period 2014-2023. Relative to the fall 2013 ten-year business plan, the most recent projection of resource need is reduced by approximately 135 MW over the same period.

Figure ES.3 – Capacity Position Comparison, 2013 IRP versus Business Plan versus 2013 IRP Update



Resource Portfolio Update

Table ES.1 reports the 2013 IRP Update resource portfolio and a comparison of portfolio changes relative to the 2013 IRP Preferred Portfolio.[1] The table shows the resource mix targeted to fill the resource need summarized above with resource capacities at time of coincident system peak reported in the years for which the resources are available to meet summer peak loads. As compared to the 2013 IRP Preferred Portfolio, the changes in resource mix for the 2014-2023 planning period are minor. Relative to the 2013 IRP Preferred Portfolio, which did not include any significant new thermal resources in the front ten years of the planning horizon, the updated resource portfolio shows a reduction in front office transactions (FOTs), consistent with a reduced resource need. As was the case in the 2013 IRP Preferred Portfolio, PacifiCorp continues to plan to meet its customers' needs largely through acquisition of cost effective energy efficiency resources and FOTs over the next ten years. Considering the relatively small changes in energy efficiency resources between the 2013 IRP and 2013 IRP Update portfolios, PacifiCorp has not modified its 2013 IRP Action Plan and continues to target accelerated energy efficiency savings.

[1] A comparison of the portfolio changes relative to the fall 2013 ten-year business plan is presented in Chapter 5.

Table ES.1 – Comparison of 2013 IRP Update with 2013 IRP Preferred Portfolio

2013 IRP Update

Summary Portfolio Capacity by Resource Type and Year, Installed MW												
	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	**645**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	**-**
DSM - Energy Efficiency	112	110	98	96	95	88	82	74	74	74	64	**854**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	2	6	2	-	-	-	-	-	-	-	-	**8**
Renewable - Distributed Solar	7	11	14	16	17	13	14	15	15	15	15	**147**
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	**11**
Front Office Transactions *	255	445	583	701	831	931	1,027	1,261	1,042	1,098	1,210	**913**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(502)	-	-		-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements	-	-	-	-	-		-	-	-	-	-	**-**
Coal Plant Gas Conversion Additions	-	-	338	-	-		-	-	-	-	-	**338**
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	**-**
Total	**391**	**1,218**	**534**	**814**	**944**	**1,034**	**1,123**	**1,351**	**1,132**	**1,189**	**1,290**	

Front Office Transactions in resource total are 10-year average. *

Difference - 2013 IRP Update Less 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW												
	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	(2)	(6)	(5)	(6)	(2)	(4)	(8)	(7)	(6)	(8)	(4)	**(55)**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	(2)	3	(1)	-	-	-	-	-	-	-	-	**2**
Renewable - Distributed Solar	-	-	-	-	(1)	(0)	-	1	-	-	-	-
Combined Heat & Power	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	(395)	(264)	(262)	(282)	(271)	(278)	(296)	(159)	(149)	(235)	(217)	**(241)**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(399)**	**(267)**	**(268)**	**(288)**	**(274)**	**(282)**	**(304)**	**(165)**	**(155)**	**(243)**	**(221)**	

Front Office Transactions in resource total are 10-year average. *

IRP Action Plan

PacifiCorp has not modified its 2013 IRP Action Plan, which remains consistent with the updated resource needs assessment and resource portfolio as summarized above. Chapter 6 of this IRP Update provides a status update of PacifiCorp's 2013 IRP Action Plan action items. A variety of action items have been completed and are noted as such, while other action items will continue forward into the 2015 IRP process.

CHAPTER 1 – INTRODUCTION

This 2013 Integrated Resource Plan Update (2013 IRP Update) describes resource planning activities that occurred subsequent to the filing of the 2013 Integrated Resource Plan (2013 IRP) in April 2013, presents an updated resource needs assessment, an updated resource portfolio consistent with changes in the planning environment, and provides an IRP Action Plan status update. In presenting the updated resource needs assessment and updated resource portfolio, PacifiCorp shows changes relative to the 2013 IRP and relative to PacifiCorp's fall 2013 ten-year business plan (Business Plan), which covers the 2014 to 2023 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2013 IRP acknowledgement process.

In support of its business planning process, PacifiCorp refined the 2013 IRP Preferred Portfolio to reflect updates to forecasted loads, resources, market prices, and other model inputs. PacifiCorp's business planning process also considers capital expenditure and operating cost constraints with input from the PacifiCorp business units (PacifiCorp Energy, Pacific Power, and Rocky Mountain Power). Consideration of both capital and operating cost constraints is critical to ensure that PacifiCorp's business plan is financially supportable and affordable to customers. The 2013 IRP Preferred Portfolio served as the primary basis in establishing the resource portfolio for the Business Plan, and as summarized herein, differences between the two resource portfolios are minor.

A similar process has been completed to develop the resource needs assessment and resource portfolio for this 2013 IRP Update, which considers updates to forecasted loads, resources, market prices, and other model inputs since the intervening Business Plan resource portfolio was developed. For purposes of assessing an updated resource needs assessment and updated resource portfolio in this 2013 IRP Update, PacifiCorp has not completed new financial analysis of pending environmental compliance decisions applicable to specific coal units on its system. PacifiCorp will analyze specific environmental compliance decisions applicable to Cholla Unit 4, Wyodak, and Dave Johnston Unit 3 in its 2015 IRP, with the full engagement of PacifiCorp's diverse stakeholder group. PacifiCorp will also provide an update on its efforts working with the Wyoming Division of Air Quality to identify amendments necessary to support the Naughton Unit 3 natural gas conversion and to clearly document the compliance requirements and timeline for implementation of the natural gas conversion under the Regional Haze program. In this 2013 IRP Update, PacifiCorp continues to assume the Naughton Unit 3 natural gas conversion is completed by summer 2015.

The 2013 IRP Update also addresses recommendations and requirements identified by its state regulatory commissions during the 2013 acknowledgement process. This includes presentation of solar resource modeling sensitivities developed in response to a request by the Public Service Commission of Utah (PSCU) of and analysis of how CO_2 price and natural gas price assumptions affect the analysis of environmental compliance decisions for specific coal units as requested by the Washington Utilities and Transportation Commission.

This report first describes the current planning environment, load updates, resource updates, emissions/climate change regulatory outlook, and Energy Gateway transmission planning and project completion forecast (Chapter 2). Next, Chapters 3 and 4 describe the changes to key inputs and assumptions relative to those used for the 2013 IRP. The updated resource portfolio is then presented along with a status update on the 2013 IRP Action Plan (Chapters 5 and 6, respectively).

Appendices include the following:

- Appendix A – Additional Load Forecast Details
- Appendix B – Executive Summary of the CHP Study
- Appendix C – Energy Analysis Report
- Appendix D – Accelerated DSM Decrement Study
- Appendix E – Correction to 2013 IRP Table A.7
- Redacted Appendix F – Breakeven Analysis for Select Coal-Fired Plants

CHAPTER 2 – PLANNING ENVIRONMENT

Business Plan Development

The 2013 IRP Preferred Portfolio served as the basis for the resource assumptions used in PacifiCorp's fall 2013 ten-year business plan (Business Plan), which covers the 2014 to 2023 planning horizon. Changes in the portfolio reflect updates to forecasted loads, resources, market prices, and other model inputs. PacifiCorp's business planning process also considers capital expenditure and operating cost constraints to ensure that the resulting business plan is financially supportable and affordable to customers. As it relates to PacifiCorp's resource plan, differences between the 2013 IRP Preferred Portfolio and the Business Plan portfolio are minor and consistent with an updated load forecast. The Business Plan portfolio also considers updated assumptions for the Energy Gateway transmission project, which continues to play an important role in the Company's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Several Energy Gateway developments have occurred since the Company's 2013 IRP was filed, including reaching construction and permitting milestones, adjusting in-service dates for future segments, and developing activities on joint-development projects. Accordingly, in-service dates have been updated relative to those assumed for the 2013 IRP. These date adjustments coincide with generation facility needs and load growth assumptions.

Cholla Unit 4 Update

In March 2011, the state of Arizona submitted its Regional Haze state implementation plan (SIP) to the Environmental Protection Agency (EPA) for review. The SIP requires currently installed low NO_X burners (LNB) as best available retrofit technology (BART) for NO_X emissions at Cholla Unit 4. By final rule dated December 5, 2012, EPA disapproved portions of the Arizona Regional Haze SIP and issued a federal implementation plan (FIP). The FIP requires, among other things, installation of selective catalytic reduction (SCR) on Cholla Unit 4 by January 4, 2018. The FIP also institutes an averaged NO_X emissions rate of 0.055 lb/MMBtu for Cholla Units 2, 3 and 4. In January and February 2013, PacifiCorp, the state of Arizona and other Arizona utilities filed separate appeals of EPA's FIP with the U.S. Ninth Circuit Court of Appeals. In February 2013, PacifiCorp and other Arizona utilities filed petitions for reconsideration at the EPA and requests for administrative stay of the FIP until judicial appeals are completed. In March 2013, PacifiCorp and other Arizona utilities filed motions for judicial stay of the FIP with the U.S. Ninth Circuit Court of Appeals until the appeals are complete.

On April 3, 2013, the court consolidated the various appeals into a single docket before a single judicial panel. On April 9, 2013, EPA granted various petitions for reconsideration for the averaged NO_X emissions rate only, but has taken no further action to date. Although EPA may propose a new NO_X rate at some time in the future, which will undergo public comment, it is not under any timing requirement to do so. EPA did not address the various requests for administrative stay in its April 9, 2013 action.

On April 23, 2013, the court set the following case schedule:

- June 2013 – briefing on motions for judicial stay to be completed
- January 2014 – briefing on the merits of appeals to be completed

On September 9, 2013, the court denied the motions for stay. The court is now expected to issue a final decision on the appeals in 2015. However, there are no mandatory dates by which the court must issue decisions.

With the denial of requests for administrative stay and judicial stay, the January 4, 2018 compliance deadline for installing SCR at Cholla Unit 4 remains in place. PacifiCorp continues to work closely with the state of Arizona and the other Arizona utilities in connection with the now consolidated appeals. Various environmental groups have intervened in the appeals in support of EPA's FIP.

With the ongoing activities outlined above, PacifiCorp continues to explore potential alternatives to the installation of SCR at Cholla Unit 4, and consequently, the Company has not finalized an analysis of compliance alternatives nor made a decision on this pending investment. The Company intends to finalize its analysis in 2014 and will file its analysis in a future IRP filing.[2] For purposes of the 2013 IRP Update, PacifiCorp assumes Cholla Unit 4 continues to provide both system capacity and energy through the planning horizon.

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 the Company's generation portfolio. PacifiCorp monitors these regulations to determine the potential impact on its generating assets. PacifiCorp also participates in the rulemaking process by filing comments on various proposals, participating in scheduled hearings, and providing assessment of such proposals.

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 can vary significantly depending on 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, etc.) and macro-economic assumptions (i.e., electricity load growth, fuel price impacts – 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

[2] The Public Utility Commission of Oregon's draft 2013 IRP acknowledgement order outlines a requirement for PacifiCorp to make a supplemental IRP filing on Cholla Unit 4 in 2014. With the appropriate protections in place, PacifiCorp intends to summarize the information from this filing for its broader stakeholder group during the 2015 IRP public process and summarize this same analysis in a confidential volume of the 2015 IRP.

been the Waxman-Markey bill in 2009 and the Kerry-Lieberman bill in 2010; neither measure was able to accumulate enough support to pass.

The 113th Congress was challenged by the President to pursue a bipartisan, market-based solution to climate change. The President stated that if Congress did not act soon, then he would direct his Cabinet to implement executive action to reduce greenhouse gas (GHG) emissions. To date, such bipartisan action has not occurred. In 2013, a bill was introduced by the Energy & Power Subcommittee Chairman Whitfield (R-KY) called the Electricity Security and Affordability Act, which provides direction to EPA regarding the establishment of standards for GHG emissions from fossil-fueled generating facilities. This bill is expected to pass the House of Representatives but not the Senate.

On June 25, 2013, President Obama directed the EPA to complete GHG standards for both new and existing power plants. With regard to existing sources, EPA was directed to issue "standards, regulations, or guidelines, as appropriate" that address GHG emissions from modified, reconstructed, and existing power plants.[3] The proposed standards, regulations, or guidelines are to be issued by June 1, 2014, finalized by June 1, 2015, with implementation of regulations as proposed in state implementation plans required by June 30, 2016. EPA would then review the implementation plan proposed by each state. The June 25, 2013 directive did not include detail with respect to how EPA will approach GHG regulation or what the resulting standards, regulations, or guidelines will ultimately entail.

Federal Renewable Portfolio Standards

Since 2010, no significant activity has occurred with respect to the development of a federal renewable portfolio standard (RPS). In addition, current political environments are shifting focus from items such as the extension of federal incentives for renewables and portfolio standards to EPA's development of greenhouse gas standards. Accordingly, the 2013 IRP Update assumes no federal RPS requirement over the course of the planning horizon.

EPA Regulatory Update – Greenhouse Gas Emissions

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.

[3] Presidential Memorandum – Power Sector Carbon Pollution Standards, June 25, 2013.

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.[4] 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 September 2013, the EPA issued a revised NSPS proposal for new fossil-fueled generating facilities and withdrew its April 2012 NSPS proposal. The new proposal would limit emissions of carbon dioxide to 1,000 pounds per megawatt hour (MWh) for large natural gas plants and 1,100 pounds per MWh for smaller natural gas plants. The revised proposal continues to largely exempt simple cycle combustion turbines from meeting the standards. The standard for new coal units would be set based on the availability of partial carbon capture and sequestration technology. The public comment period will close in May 2014 and a final rule is expected in June 2014.

[4] 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 GHG emissions from refineries with proposed regulations by December 15, 2011 and final regulations by November 15, 2012.

In January 2014, Senate Minority Leader Mitch McConnell (R-KY) filed a resolution of disapproval in an attempt to block EPA's NSPS for GHG emissions from new fossil-fueled power plants. A vote has not yet been scheduled on this resolution. In addition, in January 2014 the State of Nebraska sued the EPA in federal district court arguing that the rule's requirements for carbon capture and sequestration wrongfully rely on federally funded and unviable control technology. In support of this claim Nebraska relies on a provision of the Energy Policy Act of 2005 which restricts reliance on technology developed with federal assistance when setting performance standards.

The EPA is also under a consent decree obligation to establish GHG NSPS for modified and existing sources. Consistent with the presidential directive mentioned above, EPA has indicated that it will issue a proposed rule for existing sources in June 2014. The proposed rule to be issued by the EPA for modified and existing sources is to be used by states to develop plans for reducing emissions and/or emissions intensity and may include targets based on demonstrated controls, efficiency related emission reductions, or even beyond the fence-line compliance alternatives intended to meet best system of emissions reduction parameters. States are expected to be required to submit their implementation plans to the EPA by June 2016 pursuant to the President's direction. States are expected to 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

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 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 GHG.

Within the past few years, the EPA established new standards for particulate matter, sulfur dioxide, and nitrogen dioxide. The EPA is currently tasked with reviewing ozone standards, as well.

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. In June 2013, a petition for certiorari filed by EPA was granted by the U.S. Supreme Court, meaning until the Supreme Court issues a decision or 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, in Arizona where PacifiCorp owns but does not operate a coal unit, and in Colorado and Montana where PacifiCorp has partial ownership in generating units operated by others, but nonetheless subject to the Regional Haze Rule.

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 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. PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_x and PM SIP. 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.

The state of Wyoming 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 FIP. However, in 2013, the EPA issued a re-proposal of a NO_x and PM FIP which included substantial changes to the control equipment required in the original proposal. On January 10, 2014, the EPA issued a final action which largely approved the original Wyoming SIP. Ultimately, EPA's final determination requires installation of the following NO_x and PM controls at PacifiCorp facilities: SCR equipment and a baghouse at Naughton Unit 3 by December 31, 2014; SCR equipment at Jim Bridger Unit 3 by December 31, 2015; SCR equipment at Jim Bridger Unit 4 by December 31, 2016; SCR equipment at Jim Bridger Unit 1 by December 31, 2022; SCR equipment at Jim Bridger Unit 2 by December 31, 2021; SCR within five years or a commitment to shut down in 2027 at Dave Johnston Unit 3; and SCR at Wyodak within 5 years. With respect to Naughton Unit 3, EPA indicated its support for the conversion of the unit to natural gas and that it would expedite action relative to consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. The EPA action became final on March 3, 2014. 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. EPA's final action on the Wyoming NO_x and PM SIP may also be appealed.

The state of Arizona 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.

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 continues to plan for retirement of its Carbon facility in early 2015 as the least-cost alternative to comply with MATS and other environmental regulations. Implementation of the transmission system modifications necessary to maintain system reliability following disconnection of the Carbon facility generators from the grid are underway.

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.

The public comment period on EPA's proposal to regulate coal combustion byproducts closed in November 2010 and the EPA has indicated that the rule will be finalized in 2014. In a preamble to the recently proposed effluent guideline limitations discussed herein, EPA stated that non-hazardous management of CCRs may be adequate.

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 other 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 for once-through cooling applications. 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 rule is now expected to be finalized in the second quarter of 2014. Assuming the final rule in that timeframe, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies by mid-2015.

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. On April 19, 2013, EPA proposed revised effluent limit guidelines and is required, under the terms of a stipulated extension to a consent decree, to finalize the rule by May 2014. Until the technology-based effluent limitation guidelines are finalized, PacifiCorp is incorporating proxy compliance costs for certain units reasonably likely to be impacted by the rule into its business plans and analyses. Of importance to note, the effluent limit guidelines will also apply to gas-fired generation.

State Climate Change Regulation

While national GHG legislation has not been 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 GHGs 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 GHG emissions reduction goal into law. It directed the California Air Resources Board (CARB) to begin developing discrete early actions to reduce GHG 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, CARB adopted a GHG 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 GHG 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.

In October 2013, CARB kicked off an Assembly Bill 32 scoping plan update designed to build upon the initial scoping plan. The scoping plan update defines climate change priorities for the next five years and sets the groundwork for post-2020 climate goals. A proposed first update issued in February 2014 indicated a post-2020 GHG reduction goal of 80 percent below 1990 levels by 2050.

Oregon and Washington

In 2007, the Oregon Legislature passed HB 3543 Global Warming Actions which establishes GHG 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 Oregon Public Utility Commission (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 GHG 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.

On July 3 2013, the Oregon Legislature passed Senate Bill 306 which directs the legislative revenue officer to prepare a report examining the feasibility of imposing a clean air fee or tax as a new revenue option. The report is to include an evaluation of how to treat imported and exported energy sources. A final report is expected November 1, 2014.

In 2008, the Washington State Legislature approved the Climate Change Framework E2SHB 2815, which establishes state GHG 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. The Washington Legislature established the Climate Legislative and Executive Workgroup to develop recommendations to achieve the state's GHG emission limits. The workgroup issued two reports in January 2014; both reports included recommendations to continue workgroup efforts through 2014.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted GHG emission performance standards applicable to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emission levels of a state-of-the-art combined-cycle natural gas generation facility. The standards for Oregon and California 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 GHG based upon their global warming potential. In March 2013, the Washington Department of Commerce issued a new rule, effective April 6, 2013, lowering the emissions performance standard to 970 pounds of carbon dioxide per MWh.

Energy Gateway Transmission Program Planning

As discussed in the 2013 IRP, the Energy Gateway transmission project continues to play an important role in the Company's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. The IRP has incorporated Energy Gateway as part of a solution for delivering the least cost resource portfolio for multiple IRP planning cycles. PacifiCorp continues to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serve customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid.

Several Energy Gateway developments have occurred since the Company's 2013 IRP was filed, including reaching construction and permitting milestones, adjusting in-service dates for future segments, and developing activities on joint-development projects. Also, in response to feedback from interested stakeholders, the Company has completed its 2013 IRP Action Plan item to solicit feedback from stakeholders regarding the System Operational and Reliability Benefit Tool (SBT) that identifies and quantifies a range of transmission benefits. Please see Chapter 6 for status updates on the 2013 IRP Action Plan. An updated Energy Gateway map is provided below as Figure 2.1.

Figure 2.1 – Energy Gateway Map

Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A): The OPUC issued a Certificate of Public Convenience and Necessity (CPCN) in September 2011. In 2013, the project was delayed to allow customers to determine their need as it pertains to ongoing projects and ability to move resources to their markets. Once the customer need decision is made the future of the project will be determined and communicated to landowners and stakeholders.

Mona to Oquirrh (Segment C): Project construction is complete and the line was placed into service in May 2013. Mona to Oquirrh is the second major segment of Energy Gateway to be constructed, following Populus to Terminal (Segment B) which was placed in service in November 2010. Timing of Oquirrh to Terminal continues to be evaluated and the in-service date adjusted accordingly. Please see Table 2.1 below.

Gateway West (Segments D and E): Under the National Environmental Policy Act, the Bureau of Land Management (BLM) has completed the Environmental Impact Statement (EIS) for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the Record of Decision (ROD) on November 14, 2013, providing a right-of-way grant for all of Segment D and part of Segment E. The agency chose to defer its decision on the western-most portion of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. Given delays in the permitting activity and the bifurcation of the ROD, the in-service dates for Gateway West have been adjusted accordingly. Please see Table 2.1 below for updated segment in-service dates.

Gateway South (Segment F): The BLM's Notice of Intent was published in the Federal Register in April 2011, followed by public scoping meetings throughout the project area. Comments on this project from agencies and other interested stakeholders were considered as the BLM developed the draft EIS, which was issued in February 2014.

Sigurd to Red Butte (Segment G): The BLM issued a final record of decision in December 2012. In March 2013, a CPCN was issued by the PSCU. Construction began in May 2013 and the project is on track to be placed into service in June 2015.

West of Hemingway (Segment H): Energy Gateway Segment H represents a significant improvement in the connection between PacifiCorp's east and west control areas and will help deliver more diverse resources to serve PacifiCorp's Oregon, Washington and California customers. Originally planned as a single circuit 500 kV line from the Hemingway substation south of Boise, Idaho, to the Captain Jack substation near Klamath Falls, Oregon, the Company has continued to pursue alternative joint-development opportunities on other proposed lines west of Hemingway. In January 2012, the Company signed a permitting agreement with Idaho Power and the Bonneville Power Administration (BPA) on the proposed Boardman to Hemingway project. PacifiCorp further notes that it had a memorandum of understanding with Portland General Electric Company (PGE) with respect to the development of Cascade Crossing that terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue a Cascade Crossing solution with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp will not be actively pursuing this development. PacifiCorp will continue to look to partner with third parties on transmission development as opportunities arise.

Table 2.1 – Energy Gateway Segment In-Service Dates

Segment	2013 IRP	2013 IRP Update
Segment A: Wallula to McNary	2013-2014	Sponsor driven*
Segment C: Mona to Oquirrh	May 2013	Completed May 2013
Segment C: Oquirrh to Terminal	June 2016	May 2017*
Segment D: Windstar to Populus	2019-2021	2021-2024*
Segment E: Populus to Hemingway	2020-2023	2020-2024*
Segment F: Aeolus to Mona	2020-2022	2020-2022
Segment G: Sigurd to Red Butte	June 2015	June 2015
Segment H: West of Hemingway	Sponsor driven	

** Estimated in-service date adjusted since 2013 IRP.*

CHAPTER 3 – RESOURCE NEEDS ASSESSMENT UPDATE

Introduction

This chapter presents the update to PacifiCorp's resource needs assessment, focusing on the 2014-2023 planning period covered by the fall 2013 ten-year business plan (Business Plan). Updates to the Company's long-term load forecast, resources, and capacity position are presented and summarized.

Coincident Peak Load Forecast

Load Forecast

PacifiCorp's Business Plan reflected an updated load forecast finalized in June 2013. Relative to the load forecast prepared for the 2013 IRP, PacifiCorp system sales initially decrease in the short term and then increase over the planning period. The primary driver of the changes in the forecast are an increase in the industrial forecast due to improving economic conditions and a decrease in the residential forecast due to changes in energy efficiency and lower average-use per customer.

The coincident peak forecast decreased through the planning period due to decreases in forecast residential loads and a relatively flat peak load growth over the last five years. The coincident peak forecast decreased even though overall loads are increasing due to industrial and commercial class loads increasing relative to the decreasing residential loads and historically flat peak load growth over the last five years, which in turn reduces the long-term forecast peak load growth expectations.

In October 2013, the Company updated the load forecast for the residential class loads. Due to lower than expected weather normalized residential usage in the summer of 2013, the Company incorporated February through August 2013 actual loads for the residential class. The change between the October 2013 forecast and the June 2013 forecast reflects the changes in the residential forecast. The October 2013 load forecast is used for the 2013 IRP Update resource needs assessment.

Tables 3.1 and 3.2 report the October 2013 (2013 IRP Update) annual load and coincident peak load forecasts, respectively. Note that these forecast data exclude load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the resource portfolio.

Table 3.1 – October 2013 (2013 IRP Update): Forecasted Annual Load Growth, 2014 through 2023 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	61,671,810	14,923,360	4,486,700	893,190	25,045,480	10,363,830	3,718,360	2,240,890
2015	63,220,770	15,189,220	4,518,200	896,110	26,029,690	10,579,850	3,744,330	2,263,370
2016	63,543,020	15,330,480	4,567,610	902,370	27,064,180	10,799,120	3,777,310	1,101,950
2017	63,426,040	15,523,770	4,592,920	903,900	27,661,650	10,943,500	3,800,300	
2018	64,379,000	15,654,580	4,630,880	907,500	28,254,680	11,103,180	3,828,180	
2019	65,325,360	15,794,210	4,668,890	911,200	28,825,420	11,268,210	3,857,430	
2020	66,909,690	15,958,340	4,715,380	915,940	29,973,520	11,456,530	3,889,980	
2021	67,665,770	16,038,280	4,736,970	916,850	30,487,500	11,572,410	3,913,760	
2022	68,636,570	16,176,320	4,772,560	920,630	31,103,380	11,719,810	3,943,870	
2023	69,701,020	16,336,850	4,809,360	924,510	31,783,990	11,870,410	3,975,900	
Average Annual Growth Rate for 2014-2023								
2014-2023	**1.37%**	**1.01%**	**0.77%**	**0.38%**	**2.68%**	**1.52%**	**0.75%**	

Table 3.2 – October 2013 (2013 IRP Update): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	9,984	2,295	733	146	4,505	1,311	667	327
2015	10,152	2,338	738	147	4,574	1,335	691	330
2016	10,042	2,357	744	149	4,729	1,358	706	
2017	10,210	2,395	749	149	4,828	1,378	711	
2018	10,352	2,416	759	150	4,915	1,396	716	
2019	10,483	2,438	760	151	4,998	1,415	721	
2020	10,777	2,465	767	150	5,243	1,433	718	
2021	10,929	2,488	773	151	5,334	1,450	733	
2022	11,076	2,512	778	152	5,426	1,467	740	
2023	11,232	2,538	784	153	5,527	1,485	746	
Average Annual Growth Rate for 2013-2022								
2014-2023	**1.32%**	**1.12%**	**0.74%**	**0.52%**	**2.30%**	**1.39%**	**1.25%**	

Tables 3.3 and 3.4 report the June 2013 (Business Plan) annual load and coincident peak load forecasts, respectively. Note that these forecast data exclude load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the resource portfolio.

Table 3.3 – June 2013 (Business Plan): Forecasted Annual Load Growth, 2014 through 2023 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	62,124,830	15,005,950	4,489,050	891,410	25,394,530	10,375,030	3,727,970	2,240,890
2015	63,611,520	15,276,200	4,521,040	893,660	26,333,590	10,578,830	3,744,830	2,263,370
2016	63,973,440	15,423,510	4,570,970	899,510	27,401,880	10,797,760	3,777,860	1,101,950
2017	63,890,800	15,621,740	4,596,860	900,720	28,028,750	10,941,880	3,800,850	
2018	64,876,740	15,757,330	4,635,330	904,040	28,649,950	11,101,360	3,828,730	
2019	65,851,820	15,898,700	4,673,860	907,350	29,247,640	11,266,290	3,857,980	
2020	67,484,070	16,074,530	4,720,800	912,030	30,431,910	11,454,290	3,890,510	
2021	68,271,540	16,157,930	4,742,870	912,560	30,973,840	11,570,050	3,914,290	
2022	69,273,920	16,299,700	4,778,900	916,100	31,617,430	11,717,390	3,944,400	
2023	70,368,520	16,462,710	4,816,130	919,800	32,325,530	11,867,930	3,976,420	
Average Annual Growth Rate for 2014-2023								
2014-2023	1.39%	1.03%	0.78%	0.35%	2.72%	1.50%	0.72%	

Table 3.4 – June 2013 (Business Plan): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	10,086	2,314	735	146	4,586	1,312	668	327
2015	10,248	2,358	740	147	4,649	1,335	690	330
2016	10,144	2,379	746	148	4,810	1,357	705	
2017	10,317	2,418	752	149	4,911	1,377	710	
2018	10,463	2,440	761	149	5,001	1,396	715	
2019	10,597	2,463	763	150	5,086	1,414	720	
2020	10,898	2,492	770	149	5,338	1,433	717	
2021	11,054	2,515	776	150	5,431	1,450	732	
2022	11,205	2,540	782	151	5,526	1,467	739	
2023	11,365	2,567	787	152	5,629	1,484	745	
Average Annual Growth Rate for 2013-2022								
2014-2023	1.33%	1.16%	0.77%	0.48%	2.30%	1.38%	1.22%	

Tables 3.5 and 3.6 report the June 2012 (2013 IRP) annual load and coincident peak load forecasts, respectively. Note that these forecast data exclude load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the resource portfolio.

Table 3.5 – June 2012 (2013 IRP): Forecasted Annual Load Growth, 2014 through 2023 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
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	
2023	68,781,288	16,838,823	4,825,058	942,144	30,049,623	12,039,497	4,086,143	
Average Annual Growth Rate for 2014-2023								
2014-2023	**1.03%**	**1.18%**	**0.83%**	**0.45%**	**1.74%**	**1.63%**	**0.87%**	

Table 3.6 – June 2012 (2013 IRP): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
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	
2023	11,421	2,659	813	147	5,556	1,487	758	
Average Annual Growth Rate for 2013-2022								
2013-2022	**1.12%**	**1.25%**	**0.87%**	**0.55%**	**1.77%**	**1.49%**	**1.15%**	

Tables 3.7 and 3.8 show the October 2013 (2013 IRP Update) forecast changes relative to the June 2012 (2013 IRP) load forecast for loads and coincident system peaks, respectively.

Table 3.7 – Annual Load Growth Change: October 2013 (2013 IRP Update) Forecast less June 2012 (2013 IRP) Forecast (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	(1,026,637)	(226,819)	7,652	(11,944)	(673,471)	(44,659)	(61,067)	(16,329)
2015	(307,228)	(181,894)	7,795	(12,642)	19,308	(46,674)	(75,597)	(17,524)
2016	111,515	(307,702)	6,115	(13,634)	585,928	(57,015)	(91,038)	(11,139)
2017	179,729	(298,130)	5,059	(14,337)	651,631	(68,932)	(95,561)	
2018	159,672	(348,787)	673	(16,255)	712,421	(85,079)	(103,302)	
2019	142,173	(387,259)	(3,704)	(17,741)	751,668	(92,789)	(108,002)	
2020	683,018	(419,493)	(7,164)	(19,143)	1,350,982	(107,275)	(114,890)	
2021	748,001	(452,908)	(9,116)	(18,730)	1,466,331	(126,170)	(111,405)	
2022	822,326	(476,469)	(12,281)	(18,284)	1,588,783	(146,678)	(112,744)	
2023	919,732	(501,973)	(15,698)	(17,634)	1,734,367	(169,087)	(110,243)	

Table 3.8 – Annual Coincidental Peak Growth Change: October 2013 (2013 IRP Update) Forecast less June 2012 (2013 IRP) Forecast (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	(347)	(82)	(19)	6	(240)	9	(17)	(3)
2015	(342)	(70)	(20)	6	(253)	9	(10)	(5)
2016	(317)	(100)	(22)	6	(201)	8	(9)	
2017	(303)	(97)	(23)	5	(186)	7	(10)	
2018	(335)	(106)	(44)	5	(185)	6	(11)	
2019	(333)	(109)	(26)	5	(196)	5	(11)	
2020	(195)	(111)	(28)	5	(47)	4	(18)	
2021	(204)	(116)	(28)	6	(53)	2	(15)	
2022	(204)	(118)	(29)	6	(49)	(0)	(14)	
2023	(189)	(121)	(29)	6	(29)	(2)	(12)	

Finally, Tables 3.9 and 3.10 show the June 2013 (Business Plan) forecast changes relative to the June 2012 (2013 IRP) load forecast for loads and coincident system peaks, respectively.

Table 3.9 – Annual Load Growth Change: June 2013 (Business Plan) Forecast less June 2012 (2013 IRP) Forecast (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	(573,617)	(144,229)	10,002	(13,724)	(324,421)	(33,459)	(51,457)	(16,329)
2015	83,522	(94,914)	10,635	(15,092)	323,208	(47,694)	(75,097)	(17,524)
2016	541,935	(214,672)	9,475	(16,494)	923,628	(58,375)	(90,488)	(11,139)
2017	644,489	(200,160)	8,999	(17,517)	1,018,731	(70,552)	(95,011)	
2018	657,412	(246,037)	5,123	(19,715)	1,107,691	(86,899)	(102,752)	
2019	668,633	(282,769)	1,266	(21,591)	1,173,888	(94,709)	(107,452)	
2020	1,257,398	(303,303)	(1,744)	(23,053)	1,809,372	(109,515)	(114,360)	
2021	1,353,771	(333,258)	(3,216)	(23,020)	1,952,671	(128,530)	(110,875)	
2022	1,459,676	(353,089)	(5,941)	(22,814)	2,102,833	(149,098)	(112,214)	
2023	1,587,232	(376,113)	(8,928)	(22,344)	2,275,907	(171,567)	(109,723)	

Table 3.10 – Annual Coincidental Peak Growth Change: June 2013 (Business Plan) Forecast less June 2012 (2013 IRP) Forecast (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2014	(245)	(64)	(17)	5	(159)	10	(17)	(3)
2015	(246)	(50)	(18)	6	(177)	9	(11)	(5)
2016	(215)	(78)	(19)	6	(121)	8	(10)	
2017	(196)	(73)	(20)	5	(103)	7	(10)	
2018	(224)	(81)	(42)	4	(99)	6	(12)	
2019	(219)	(84)	(23)	4	(108)	5	(12)	
2020	(74)	(85)	(25)	5	47	3	(20)	
2021	(78)	(88)	(25)	5	44	1	(16)	
2022	(75)	(90)	(25)	5	51	(1)	(15)	
2023	(56)	(92)	(26)	5	73	(3)	(13)	

See also Appendix A for further load details.

Resource Updates

Existing and Firm Resources

The availability and capacity contribution from existing resources have been reviewed and updated to reflect changes since the inputs were locked down for the 2013 IRP. The most recent results of this review process are summarized for the 2013 IRP Update and for the intervening Business Plan, aligning with updates made to PacifiCorp's load forecast since filing of its 2013 IRP as discussed above. Updates to existing and firm resources are presented in two steps - from the 2013 IRP to the Business Plan and from the Business Plan to the 2013 IRP Update. Updates applied in each of these steps include:

Business Plan

- Added new, and updated existing contracts to reflect changes between the 2013 IRP and the Business Plan. Adjustments to existing firm contracts and inclusion of new sales contracts result in a net increase of firm sales that average 54 MW annually over the 2014 to 2024 period. Since filing the 2013 IRP, there is also an incremental 25 MW purchase in 2014.

- The peak contribution of wind resources was updated from 4.2% (2013 IRP) to 4.0% (Business Plan). The update reflects inclusion of 2011 and 2012 historical data using the same methodology as described in Volume II, Appendix O of PacifiCorp's 2013 IRP.[5] Updated wind generation profiles.

- Updated reserve obligations for non-owned generation is reduced by 106 MW by 2015.

- The hydro generation forecast is updated to reflect the forecast developed in support of Business Plan, reflecting then current projections for hydro operations accounting for planned water conditions, availability, and market prices. Over the 2014 to 2024 period, the average peak contribution of hydro generation is reduced by 16 MW annually.

2013 IRP Update

- Included ten new qualifying facility contracts representing approximately 10 MW of peak capacity that were entered into following development of the Business Plan. These contracts are scheduled to come online in 2015 and 2016.

- Included a new 25 MW sale contract that was entered into following development of the Business Plan. The contract expires year-end 2014.

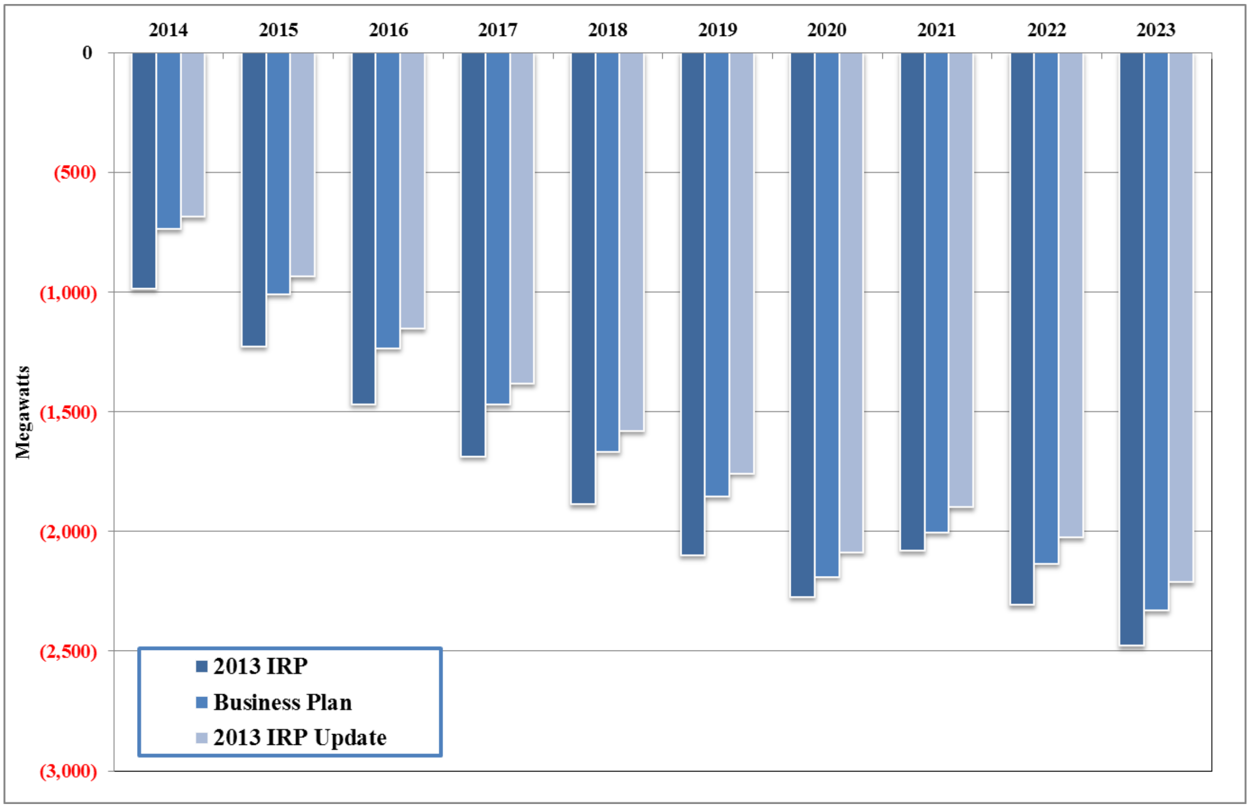
Updated Capacity Load and Resource Balance

Figure 3.1 shows the 2013 IRP Update resource need, prior to acquiring any new resources, alongside the resource need from the 2013 IRP and the Business Plan. Overall, the forecasted

[5] PacifiCorp includes a set of sensitivity studies showing resource portfolio impacts of using alternative capacity contribution assumptions for both wind and solar resources in Chapter 5.

need has declined with the most recent needs assessment. Primarily driven by an updated load forecast, the most recent resource needs assessment shows an average reduction in peak resource need of approximately 320 MW as compared to the 2013 IRP for the period 2014-2023. Relative to the Business Plan, the most recent projection of resource need is reduced by approximately 135 MW over the same period.

Figure 3.1 – Capacity Position Comparison, 2013 IRP versus Business Plan versus 2013 IRP Update



Tables 3.11 through 3.13 report the capacity load and resource line items from the 2013 IRP Update, Business Plan, and 2013 IRP respectively. Differences between the line items for the 2013 IRP and 2013 IRP Update are in Table 3.14, while differences between the line items for the 2013 IRP and Business Plan are in Table 3.15.

Table 3.11 – Load and Resource Balance, 2013 IRP Update (Megawatts)

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	111	110	125	125	122	125	125	125	125	125
Renewable	92	82	82	82	82	82	82	81	81	79
Purchase	662	662	425	312	312	312	312	283	283	283
Qualifying Facilities	79	83	93	93	93	93	93	92	88	88
Sale	(763)	(738)	(738)	(663)	(663)	(663)	(663)	(183)	(183)	(183)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**6,769**	**6,621**	**6,403**	**6,365**	**6,362**	**6,365**	**6,365**	**6,814**	**6,810**	**6,808**
Load	6,810	6,930	6,792	6,916	7,028	7,133	7,395	7,517	7,635	7,757
Existing Resources:										
Interruptible	(159)	(159)	(186)	(186)	(186)	(186)	(186)	(186)	(186)	(186)
Class 1 DSM	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)
East obligation	**6,322**	**6,442**	**6,277**	**6,401**	**6,513**	**6,618**	**6,880**	**7,002**	**7,120**	**7,242**
Planning Reserves (13%)	822	837	816	832	847	860	894	910	926	941
East Reserves	**822**	**837**	**816**	**832**	**847**	**860**	**894**	**910**	**926**	**941**
East Obligation + Reserves	**7,144**	**7,279**	**7,093**	**7,233**	**7,360**	**7,478**	**7,774**	**7,912**	**8,046**	**8,183**
East Position	**(375)**	**(658)**	**(690)**	**(868)**	**(998)**	**(1,113)**	**(1,409)**	**(1,098)**	**(1,236)**	**(1,375)**
East Reserve Margin	7.1%	2.8%	2.0%	(0.6%)	(2.3%)	(3.8%)	(7.5%)	(2.7%)	(4.4%)	(6.0%)
West										
Thermal	2,524	2,524	2,506	2,503	2,503	2,503	2,503	2,503	2,500	2,497
Hydroelectric	777	775	774	774	747	730	734	641	652	652
Renewable	38	38	38	38	38	38	38	38	21	21
Purchase	187	190	21	21	21	3	3	3	3	3
Qualifying Facilities	99	86	76	76	71	71	71	71	71	67
Sale	(306)	(207)	(157)	(156)	(156)	(157)	(157)	(153)	(100)	(102)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,316**	**3,403**	**3,255**	**3,253**	**3,221**	**3,185**	**3,189**	**3,100**	**3,144**	**3,135**
Load	3,174	3,221	3,251	3,294	3,325	3,349	3,382	3,412	3,442	3,475
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
West obligation	**3,174**	**3,221**	**3,251**	**3,294**	**3,325**	**3,349**	**3,382**	**3,412**	**3,442**	**3,475**
Planning Reserves (13%)	413	419	423	428	432	435	440	444	447	452
West Reserves	**413**	**419**	**423**	**428**	**432**	**435**	**440**	**444**	**447**	**452**
West Obligation + Reserves	**3,587**	**3,640**	**3,674**	**3,722**	**3,757**	**3,784**	**3,822**	**3,856**	**3,889**	**3,927**
West Position	**(271)**	**(237)**	**(419)**	**(469)**	**(536)**	**(599)**	**(633)**	**(756)**	**(745)**	**(792)**
West Reserve Margin	4.5%	5.7%	0.1%	(1.2%)	(3.1%)	(4.9%)	(5.7%)	(9.1%)	(8.7%)	(9.8%)
System										
Total Resources	10,085	10,024	9,658	9,618	9,583	9,550	9,554	9,914	9,954	9,943
Obligation	9,496	9,663	9,528	9,695	9,838	9,967	10,262	10,414	10,562	10,717
Reserves	1,234	1,256	1,239	1,260	1,279	1,296	1,334	1,354	1,373	1,393
Obligation + Reserves	10,730	10,919	10,767	10,955	11,117	11,263	11,596	11,768	11,935	12,110
System Position	(645)	(895)	(1,109)	(1,337)	(1,534)	(1,713)	(2,042)	(1,854)	(1,981)	(2,167)
Reserve Margin	6.2%	3.7%	1.4%	(0.8%)	(2.6%)	(4.2%)	(6.9%)	(4.8%)	(5.8%)	(7.2%)

Table 3.12 – Load and Resource Balance, Business Plan (Megawatts)

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	111	110	125	125	122	125	125	125	125	125
Renewable	92	82	82	82	82	82	82	81	81	79
Purchase	662	662	425	312	312	312	312	283	283	283
Qualifying Facilities	79	80	83	83	83	83	83	82	78	78
Sale	(738)	(738)	(738)	(663)	(663)	(663)	(663)	(183)	(183)	(183)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**6,794**	**6,618**	**6,393**	**6,355**	**6,352**	**6,355**	**6,355**	**6,804**	**6,800**	**6,798**
Load	6,892	7,004	6,872	7,000	7,113	7,221	7,487	7,612	7,731	7,859
Existing Resources:										
Interruptible	(159)	(159)	(186)	(186)	(186)	(186)	(186)	(186)	(186)	(186)
Class 1 DSM	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)
East obligation	**6,404**	**6,516**	**6,357**	**6,485**	**6,598**	**6,706**	**6,972**	**7,097**	**7,216**	**7,344**
Planning Reserves (13%)	833	847	826	843	858	872	906	923	938	955
East Reserves	**833**	**847**	**826**	**843**	**858**	**872**	**906**	**923**	**938**	**955**
East Obligation + Reserves	**7,237**	**7,363**	**7,183**	**7,328**	**7,456**	**7,578**	**7,878**	**8,020**	**8,154**	**8,299**
East Position	**(443)**	**(745)**	**(790)**	**(973)**	**(1,104)**	**(1,223)**	**(1,523)**	**(1,216)**	**(1,354)**	**(1,501)**
East Reserve Margin	6.1%	1.6%	0.6%	(2.0%)	(3.7%)	(5.2%)	(8.8%)	(4.1%)	(5.8%)	(7.4%)
West										
Thermal	2,524	2,524	2,506	2,503	2,503	2,503	2,503	2,503	2,500	2,497
Hydroelectric	777	775	774	774	747	730	734	641	652	652
Renewable	38	38	38	38	38	38	38	38	21	21
Purchase	187	190	21	21	21	3	3	3	3	3
Qualifying Facilities	99	86	76	76	71	71	71	71	71	67
Sale	(306)	(207)	(157)	(156)	(156)	(157)	(157)	(153)	(100)	(102)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,316**	**3,403**	**3,255**	**3,253**	**3,221**	**3,185**	**3,189**	**3,100**	**3,144**	**3,135**
Load	3,195	3,244	3,272	3,318	3,350	3,377	3,412	3,442	3,473	3,508
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
West obligation	**3,195**	**3,244**	**3,272**	**3,318**	**3,350**	**3,377**	**3,412**	**3,442**	**3,473**	**3,508**
Planning Reserves (13%)	415	422	425	431	436	439	444	447	451	456
West Reserves	**415**	**422**	**425**	**431**	**436**	**439**	**444**	**447**	**451**	**456**
West Obligation + Reserves	**3,610**	**3,666**	**3,697**	**3,749**	**3,786**	**3,816**	**3,856**	**3,889**	**3,924**	**3,964**
West Position	**(294)**	**(263)**	**(442)**	**(496)**	**(565)**	**(631)**	**(667)**	**(789)**	**(780)**	**(829)**
West Reserve Margin	3.8%	4.9%	(0.5%)	(2.0%)	(3.9%)	(5.7%)	(6.5%)	(9.9%)	(9.5%)	(10.6%)
System										
Total Resources	10,110	10,021	9,648	9,608	9,573	9,540	9,544	9,904	9,944	9,933
Obligation	9,599	9,760	9,629	9,803	9,948	10,083	10,384	10,539	10,689	10,852
Reserves	1,248	1,269	1,252	1,274	1,293	1,311	1,350	1,370	1,390	1,411
Obligation + Reserves	10,847	11,029	10,881	11,077	11,241	11,394	11,734	11,909	12,079	12,263
System Position	(737)	(1,008)	(1,233)	(1,469)	(1,668)	(1,854)	(2,190)	(2,005)	(2,135)	(2,330)
Reserve Margin	5.3%	2.7%	0.2%	(2.0%)	(3.8%)	(5.4%)	(8.1%)	(6.0%)	(7.0%)	(8.5%)

Table 3.13 – Load and Resource Balance, 2013 IRP (Megawatts)

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	140	140	135	135	132	135	135	135	135	135
Renewable	85	83	83	83	83	83	83	82	80	80
Purchase	611	611	398	285	285	285	285	257	257	257
Qualifying Facilities	73	73	73	73	73	73	73	73	25	25
Sale	(732)	(730)	(724)	(638)	(638)	(638)	(639)	(158)	(158)	(158)
Non-Owned Reserves	(103)	(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)
East Existing Resources	**6,700**	**6,499**	**6,281**	**6,254**	**6,251**	**6,254**	**6,253**	**6,705**	**6,655**	**6,655**
Load	7,061	7,188	6,994	7,105	7,217	7,337	7,455	7,584	7,697	7,802
Existing Resources:										
Interruptible	(143)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
Class 1 DSM	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)	(379)
East obligation	**6,539**	**6,654**	**6,460**	**6,571**	**6,683**	**6,803**	**6,921**	**7,050**	**7,163**	**7,268**
Planning Reserves (13%)	850	865	840	854	869	884	900	917	931	945
East Reserves	**850**	**865**	**840**	**854**	**869**	**884**	**900**	**917**	**931**	**945**
East Obligation + Reserves	**7,389**	**7,519**	**7,300**	**7,425**	**7,552**	**7,687**	**7,821**	**7,967**	**8,094**	**8,213**
East Position	**(689)**	**(1,020)**	**(1,019)**	**(1,171)**	**(1,301)**	**(1,433)**	**(1,568)**	**(1,262)**	**(1,439)**	**(1,558)**
East Reserve Margin	2%	(2%)	(3%)	(5%)	(6%)	(8%)	(10%)	(5%)	(7%)	(8%)
West										
Thermal	2,524	2,524	2,520	2,503	2,503	2,503	2,503	2,503	2,500	2,497
Hydroelectric	751	776	782	780	780	723	726	647	650	648
Renewable	36	36	36	36	36	36	36	36	19	19
Purchase	225	231	13	13	13	2	2	2	2	2
Qualifying Facilities	99	99	89	89	89	88	89	89	89	85
Sale	(260)	(160)	(110)	(110)	(110)	(110)	(110)	(109)	(103)	(103)
Non-Owned Reserves	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
West Existing Resources	**3,366**	**3,497**	**3,321**	**3,302**	**3,302**	**3,233**	**3,237**	**3,159**	**3,148**	**3,139**
Load	3,269	3,307	3,365	3,407	3,470	3,479	3,516	3,549	3,583	3,620
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
West obligation	**3,241**	**3,279**	**3,337**	**3,379**	**3,442**	**3,451**	**3,488**	**3,521**	**3,555**	**3,592**
Planning Reserves (13%)	421	426	434	439	447	449	453	458	462	467
West Reserves	**421**	**426**	**434**	**439**	**447**	**449**	**453**	**458**	**462**	**467**
West Obligation + Reserves	**3,662**	**3,705**	**3,771**	**3,818**	**3,889**	**3,900**	**3,941**	**3,979**	**4,017**	**4,059**
West Position	**(296)**	**(208)**	**(450)**	**(516)**	**(587)**	**(667)**	**(704)**	**(820)**	**(869)**	**(920)**
West Reserve Margin	4%	7%	(0%)	(2%)	(4%)	(6%)	(7%)	(10%)	(11%)	(13%)
System										
Total Resources	10,066	9,996	9,602	9,556	9,553	9,487	9,490	9,864	9,803	9,794
Obligation	9,780	9,933	9,797	9,950	10,125	10,254	10,409	10,571	10,718	10,860
Reserves	1,271	1,291	1,274	1,294	1,316	1,333	1,353	1,374	1,393	1,412
Obligation + Reserves	11,051	11,224	11,071	11,244	11,441	11,587	11,762	11,945	12,111	12,272
System Position	(985)	(1,228)	(1,469)	(1,688)	(1,888)	(2,100)	(2,272)	(2,081)	(2,308)	(2,478)
Reserve Margin	3%	1%	(2%)	(4%)	(6%)	(7%)	(9%)	(7%)	(9%)	(10%)

Table 3.14 – Load and Resource Balance, 2013 IRP Update less 2013 IRP (Megawatts)

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	(29)	(30)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
Renewable	7	(1)	(1)	(1)	(1)	(1)	(1)	(1)	1	(1)
Purchase	51	51	27	27	27	27	27	26	26	26
Qualifying Facilities	6	10	20	20	20	20	20	19	63	63
Sale	(31)	(8)	(14)	(25)	(25)	(25)	(24)	(25)	(25)	(25)
Non-Owned Reserves	65	100	100	100	100	100	100	100	100	100
East Existing Resources	**69**	**122**	**122**	**111**	**111**	**111**	**112**	**109**	**155**	**153**
Load	(251)	(258)	(202)	(189)	(189)	(204)	(60)	(67)	(62)	(45)
Existing Resources:										
Interruptible	(16)	(4)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
DSM	50	50	50	50	50	50	50	50	50	50
East obligation	**(217)**	**(212)**	**(183)**	**(170)**	**(170)**	**(185)**	**(41)**	**(48)**	**(43)**	**(26)**
Planning Reserves (13%)	(28)	(28)	(24)	(22)	(22)	(24)	(5)	(6)	(6)	(3)
East Reserves	**(28)**	**(28)**	**(24)**	**(22)**	**(22)**	**(24)**	**(5)**	**(6)**	**(6)**	**(3)**
East Obligation + Reserves	**(245)**	**(240)**	**(207)**	**(192)**	**(192)**	**(209)**	**(46)**	**(54)**	**(49)**	**(29)**
East Position	**314**	**362**	**329**	**303**	**303**	**320**	**158**	**163**	**204**	**182**
East Reserve Margin	5%	5%	5%	4%	4%	4%	2%	2%	3%	2%
West										
Thermal	0	0	(14)	0	0	0	0	0	0	0
Hydroelectric	26	(1)	(8)	(6)	(33)	7	8	(6)	2	4
Renewable	2	2	2	2	2	2	2	2	2	2
Purchase	(38)	(41)	8	8	8	1	1	1	1	1
Qualifying Facilities	0	(13)	(13)	(13)	(18)	(17)	(18)	(18)	(18)	(18)
Sale	(46)	(47)	(47)	(46)	(46)	(47)	(47)	(44)	3	1
Non-Owned Reserves	6	6	6	6	6	6	6	6	6	6
West Existing Resources	**(50)**	**(94)**	**(66)**	**(49)**	**(81)**	**(48)**	**(48)**	**(59)**	**(4)**	**(4)**
Load	(95)	(86)	(114)	(113)	(145)	(130)	(134)	(137)	(141)	(145)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	28	28	28	28	28	28	28	28	28	28
West obligation	**(67)**	**(58)**	**(86)**	**(85)**	**(117)**	**(102)**	**(106)**	**(109)**	**(113)**	**(117)**
Planning Reserves (13%)	(9)	(8)	(11)	(11)	(15)	(13)	(14)	(14)	(15)	(15)
West Reserves	**(9)**	**(8)**	**(11)**	**(11)**	**(15)**	**(13)**	**(14)**	**(14)**	**(15)**	**(15)**
West Obligation + Reserves	**(76)**	**(66)**	**(97)**	**(96)**	**(132)**	**(115)**	**(120)**	**(123)**	**(128)**	**(132)**
West Position	**26**	**(28)**	**31**	**47**	**51**	**67**	**72**	**64**	**124**	**128**
West Reserve Margin	1%	(1%)	1%	1%	1%	1%	1%	1%	3%	3%
System										
Total Resources	19	28	56	62	30	63	64	50	151	149
Obligation	(284)	(270)	(269)	(255)	(287)	(287)	(147)	(157)	(156)	(143)
Reserves	(37)	(35)	(35)	(33)	(37)	(37)	(19)	(20)	(20)	(19)
Obligation + Reserves	(321)	(305)	(304)	(288)	(324)	(324)	(166)	(177)	(176)	(162)
System Position	340	333	360	350	354	387	230	227	327	311
Reserve Margin	3%	3%	3%	3%	3%	3%	2%	2%	3%	3%

Table 3.15 – Load and Resource Balance, Business Plan less 2013 IRP (Megawatts)

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	(29)	(30)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
Renewable	7	(1)	(1)	(1)	(1)	(1)	(1)	(1)	1	(1)
Purchase	51	51	27	27	27	27	27	26	26	26
Qualifying Facilities	6	7	10	10	10	10	10	9	53	53
Sale	(6)	(8)	(14)	(25)	(25)	(25)	(24)	(25)	(25)	(25)
Non-Owned Reserves	65	100	100	100	100	100	100	100	100	100
East Existing Resources	**94**	**119**	**112**	**101**	**101**	**101**	**102**	**99**	**145**	**143**
Load	(169)	(184)	(122)	(105)	(104)	(116)	32	28	34	57
Existing Resources:										
Interruptible	(16)	(4)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
DSM	50	50	50	50	50	50	50	50	50	50
East obligation	**(135)**	**(138)**	**(103)**	**(86)**	**(85)**	**(97)**	**51**	**47**	**53**	**76**
Planning Reserves (13%)	(18)	(18)	(13)	(11)	(11)	(13)	7	6	7	10
East Reserves	**(18)**	**(18)**	**(13)**	**(11)**	**(11)**	**(13)**	7	**6**	7	**10**
East Obligation + Reserves	**(153)**	**(156)**	**(116)**	**(97)**	**(96)**	**(110)**	**58**	**53**	**60**	**86**
East Position	**247**	**275**	**228**	**198**	**197**	**211**	**44**	**46**	**85**	**57**
East Reserve Margin	4%	4%	3%	3%	3%	3%	1%	1%	1%	1%
West										
Thermal	0	0	(14)	0	0	0	0	0	0	0
Hydroelectric	26	(1)	(8)	(6)	(33)	7	8	(6)	2	4
Renewable	2	2	2	2	2	2	2	2	2	2
Purchase	(38)	(41)	8	8	8	1	1	1	1	1
Qualifying Facilities	0	(13)	(13)	(13)	(18)	(17)	(18)	(18)	(18)	(18)
Sale	(46)	(47)	(47)	(46)	(46)	(47)	(47)	(44)	3	1
Non-Owned Reserves	6	6	6	6	6	6	6	6	6	6
West Existing Resources	**(50)**	**(94)**	**(66)**	**(49)**	**(81)**	**(48)**	**(48)**	**(59)**	**(4)**	**(4)**
Load	(74)	(63)	(93)	(89)	(120)	(102)	(104)	(107)	(110)	(112)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	28	28	28	28	28	28	28	28	28	28
West obligation	**(46)**	**(35)**	**(65)**	**(61)**	**(92)**	**(74)**	**(76)**	**(79)**	**(82)**	**(84)**
Planning Reserves (13%)	(6)	(5)	(8)	(8)	(12)	(10)	(10)	(10)	(11)	(11)
West Reserves	**(6)**	**(5)**	**(8)**	**(8)**	**(12)**	**(10)**	**(10)**	**(10)**	**(11)**	**(11)**
West Obligation + Reserves	**(52)**	**(40)**	**(73)**	**(69)**	**(104)**	**(84)**	**(86)**	**(89)**	**(93)**	**(95)**
West Position	**2**	**(54)**	7	**20**	**23**	**36**	**38**	**30**	**89**	**91**
West Reserve Margin	(0%)	(2%)	(0%)	0%	0%	1%	1%	0%	2%	2%
System										
Total Resources	44	25	46	52	20	53	54	40	141	139
Obligation	(181)	(173)	(168)	(147)	(177)	(171)	(25)	(32)	(29)	(8)
Reserves	(24)	(22)	(22)	(19)	(23)	(22)	(3)	(4)	(4)	(1)
Obligation + Reserves	(205)	(195)	(190)	(166)	(200)	(193)	(28)	(36)	(33)	(9)
System Position	249	220	236	218	220	246	82	76	174	148
Reserve Margin	2%	2%	2%	2%	2%	2%	1%	1%	2%	1%

Figures 3.2 through 3.4 summarize for the 2013 IRP Update annual capacity position for the system, west balancing area, and east balancing area, respectively.

Figure 3.2 – 2013 IRP Update, System Capacity Position Trend

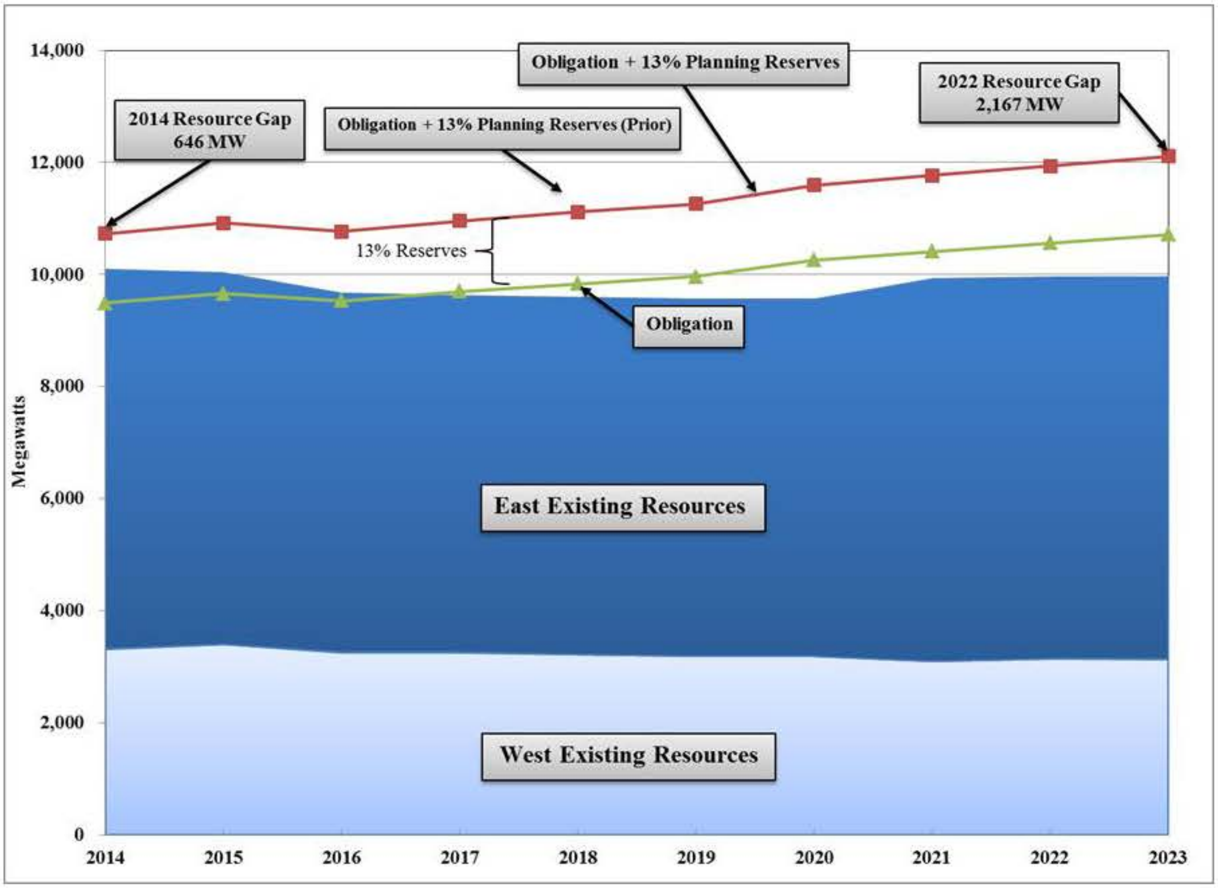


Figure 3.3 – 2013 IRP Update, West Capacity Position Trend

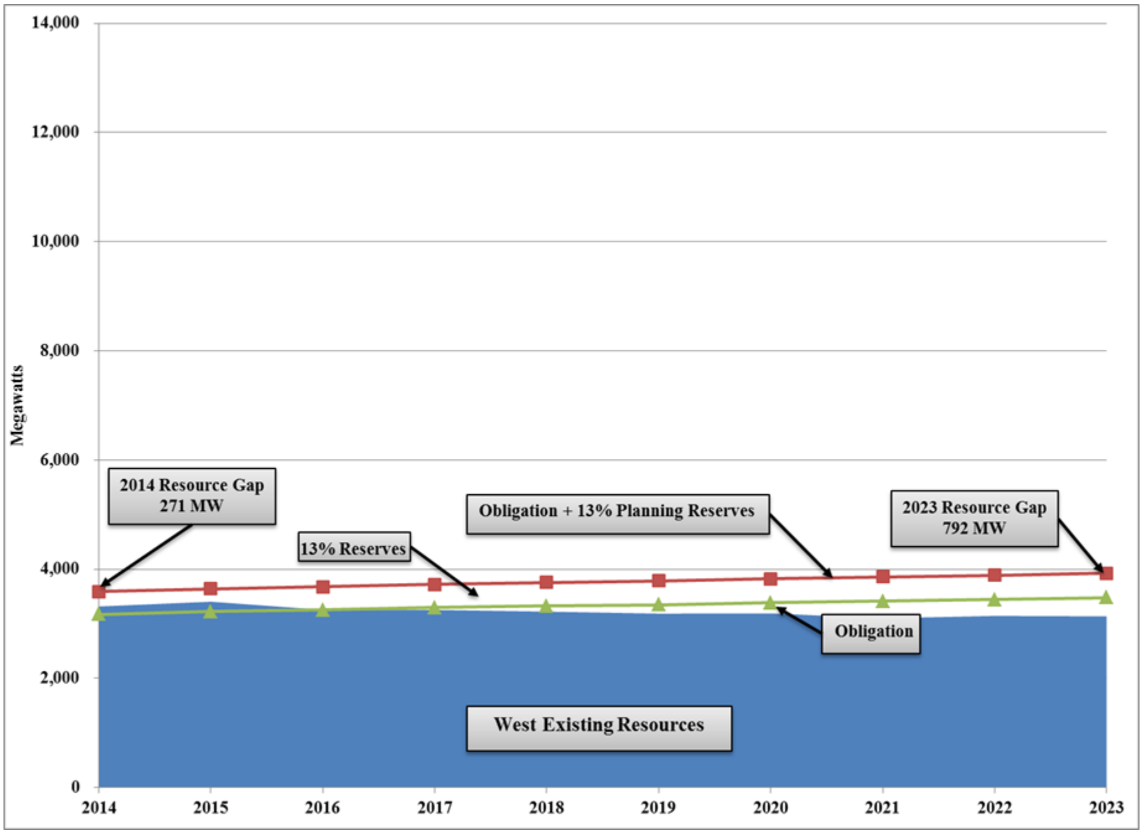
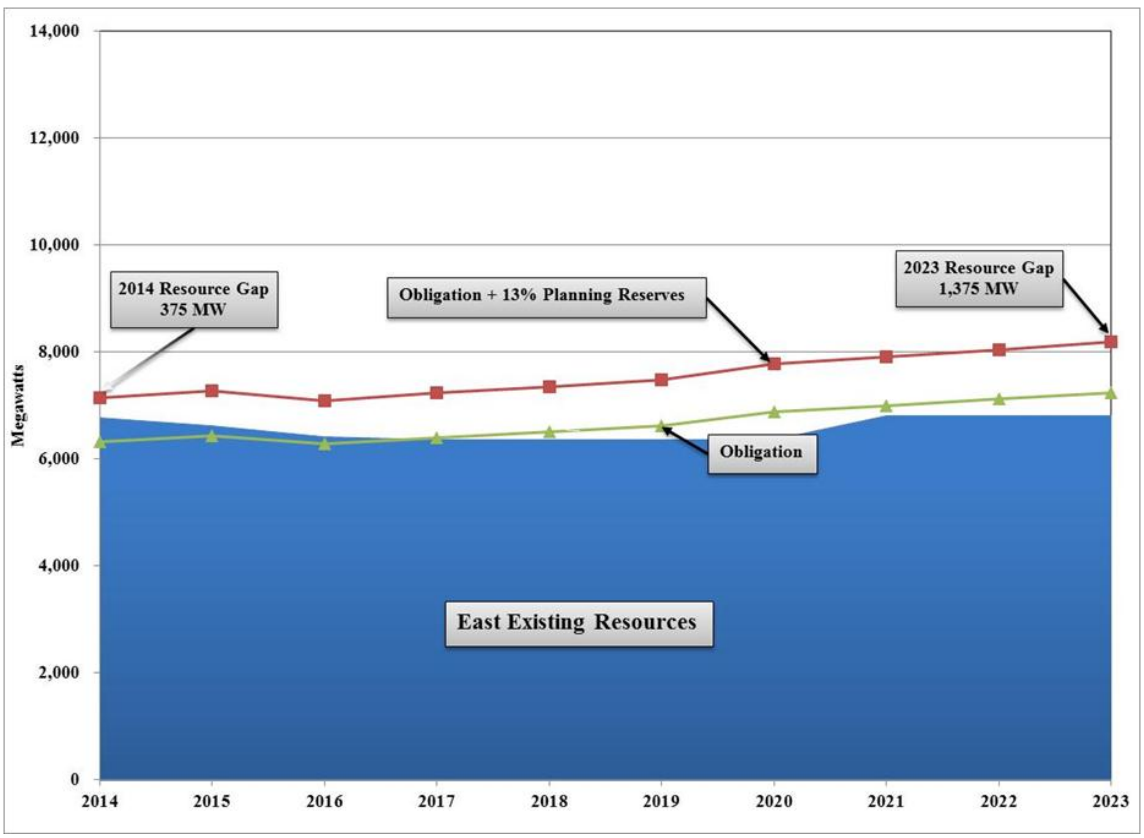


Figure 3.4 – 2013 IRP Update, East Capacity Position Trend



On a total Company basis, the Business Plan sensitivity shows that the peak resource need has fallen by over 200 MW through 2019 and approximately 100 MW in the later years as compared to the 2013 IRP. On a total Company basis, the 2013 IRP Update shows further reduction in resource needs from the Business Plan. This is mainly due to a further reduction in the load forecast. As compared to the 2013 IRP, changes to the resource needs assessment are driven by the following:

PacifiCorp East

- Average annual peak loads are forecast 215 MW lower over the 2014-2019 timeframe and 59 MW lower over the 2020-2024 timeframe.
- Updates to existing resources and additions of new sale and purchase contracts net to an average increase in system capacity of approximately 21 MW over the 2014-2023 timeframe.
- Updates to non-owned reserves reduce PacifiCorp's planning obligation by 65 MW in 2014 and 100 MW over the 2015-2023 timeframe.

PacifiCorp West

- Average annual peak loads are forecast 124 MW lower over the 2014-2023 timeframe.
- Updates to existing resources and additions of new sale and purchase contracts net to an average decrease in system capacity averaging 66 MW over the 2014-2021 timeframe and 10 MW in 2022 and 2023.
- Updates to non-owned reserves reduce PacifiCorp's planning obligation of 6 MW in each year of the 2014-2023 planning period.

System

- Primarily driven by lower forecast peak load, the average annual system obligation plus planning reserves is reduced by 311 MW over the 2014-2019 timeframe and by 177 MW over the 2020-2023 timeframe.
- After accounting for updates to existing resources, additions of new sale and purchase contracts, an updated non-owned reserves, the average system capacity position required to achieve a 13% planning reserve margin has improved by 352 MW over the 2014-2019 period and by 274 MW over the 2020-2023 timeframe.

CHAPTER 4 – MODELING ASSUMPTIONS UPDATE

General Assumptions

In line with the 2013 IRP, the study period for both the fall 2013 ten-year business plan (Business Plan) sensitivity and the 2013 IRP Update studies is 2013 through 2032, with a focus on the 2014-2023 planning horizon. Updated resource portfolios were developed assuming a 13% planning reserve margin consistent with the stochastic loss of load probability study included in the 2013 IRP.

PacifiCorp has not made any changes to general inflation assumptions (1.9%) and has not modified its discount factor (6.882%) in this 2013 IRP Update. PacifiCorp continues to assume federal production tax credits are expired and that federal investment tax credits for qualifying renewable resources will expire at the end of 2016.

Natural Gas and Power Market Price Updates

The Business Plan portfolio modeling was based upon PacifiCorp's September 30, 2013 official forward price curve (OFPC). Portfolio modeling for the 2013 IRP Update was prepared using PacifiCorp's December 31, 2013 OFPC. All OFPCs in the 2013 IRP and IRP Update are composed of market forwards for the first 72 months, followed by 12 months of blended prices which transition to a market fundamentals-based forecast, starting in month 85. An OFPC is produced for both natural gas and power prices by point of delivery. The fundamentals forecast for natural gas is selected from three expert third-party sources with consideration given to underlying supply/demand assumptions, forecast documentation, peer-to-peer forecast price comparisons, date of issuance, location granularity, and forecast horizon. Natural gas price forecasts are a key driver of electricity price forecasts, as produced by MIDAS, a production cost simulation model.

Natural Gas Market Prices

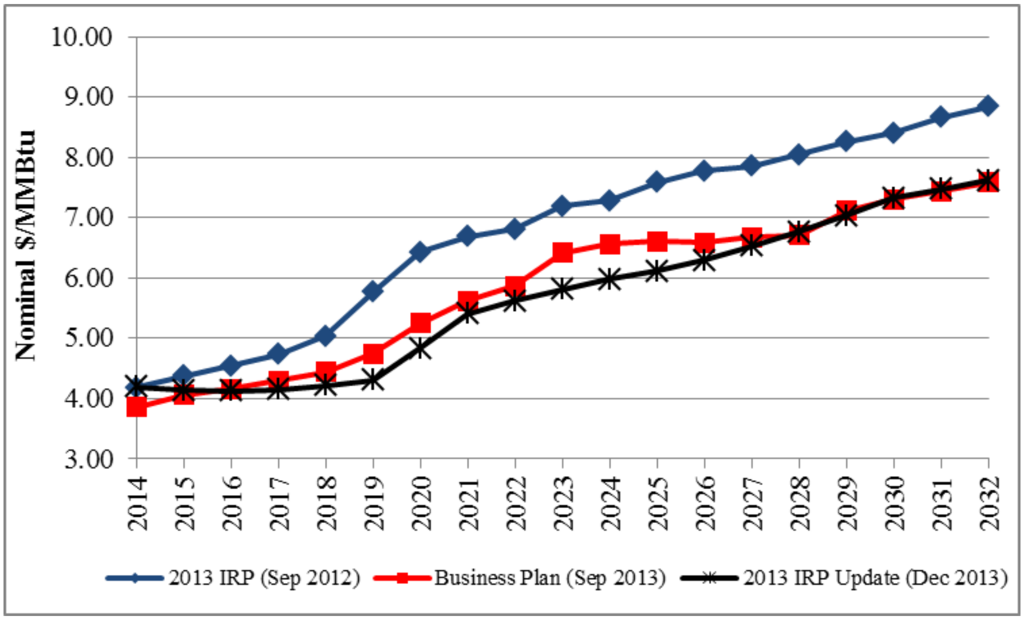
The fundamentals portion of the September 2013 natural gas OFPC is based on expert third-party long-term gas price forecasts issued between May 2013 and September 2013 with short-term updates in August 2013. The fundamentals portion of the December 2013 natural gas OFPC was based on expert third-party long-term gas price forecasts issued between October 2013 and December 2013 with short-term updates in November and December 2013. Both the September 2013 and December 2013 natural gas OFPCs reflect a fundamentals-based forecast heavily influenced by cost-effective domestic supply opportunities largely due to growth in unconventional shale gas plays.

The September 2012 natural gas OFPC, which was used in the 2013 IRP, was based on an expert third-party long-term natural gas forecast issued May 2012 with a short-term update in August 2012. The September 2012 OFPC also reflects a considerable portion of domestic natural gas demand being met by unconventional shale production.

In summer 2012, surveyed expert third-party natural gas price forecasters expected 50% -58% of 2020 production to come from shale, by summer 2013 expectations had increased to 50% - 67%, and by winter 2013 expectations ranged from 50% - 71%. In the course of one year alone, 2012 to 2013, Marcellus production increased from approximately seven billion cubic feet per day (BCF/D) to over 11 BCF/D.

Figure 4.1 compares the nominal annual Henry Hub natural gas prices from the September 2012 (2013 IRP), September 2013 (Business Plan), and December 2013 OFPCs (2013 IRP Update).

Figure 4.1 – Henry Hub Natural Gas Prices (Nominal)



Power Market Prices

The natural gas fundamentals forecast described above was a key input to the MIDAS model, and consequently, the gas curve shape is reflected in the electricity prices from the September 2012, September 2013, and December 2013 OFPCs. Figures 4.2 through 4.5 compare the average annual electricity prices for the Palo Verde and Mid-Columbia market hubs from the September 2012, September 2013, and December 2013 OFPCs.

Figure 4.2 – Average Annual Flat Palo Verde Electricity Prices

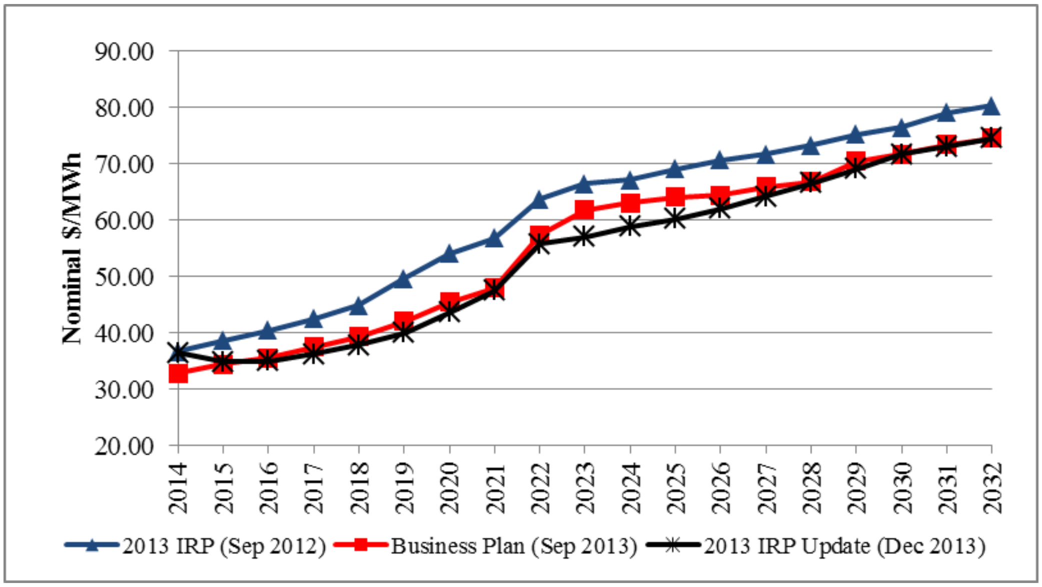


Figure 4.3 – Average Annual Heavy Load Hour Palo Verde Electricity Prices

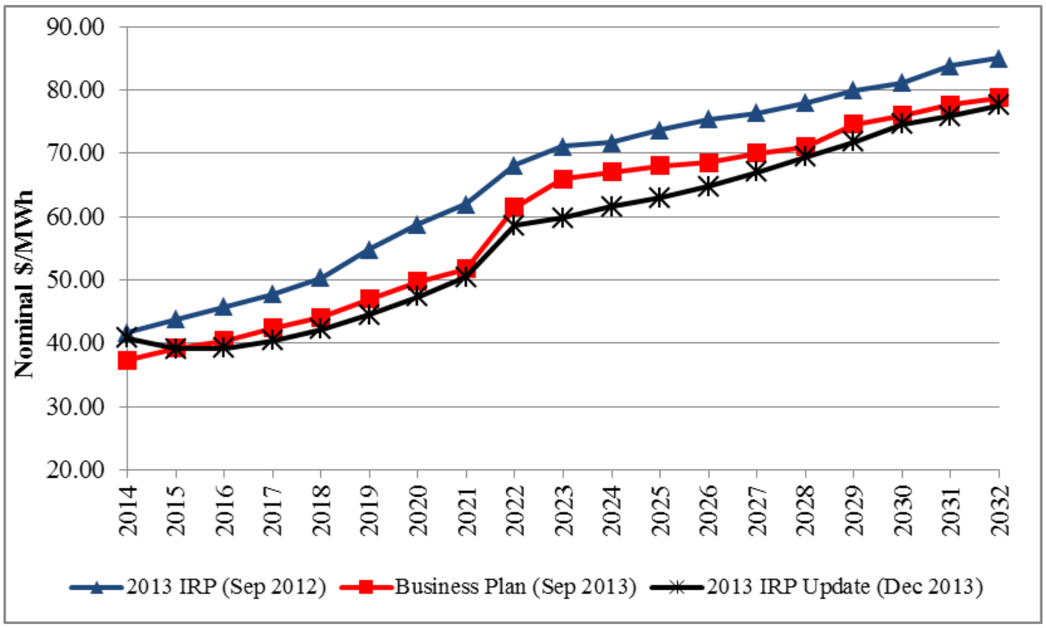


Figure 4.4 – Average Annual Flat Mid-Columbia Electricity Prices

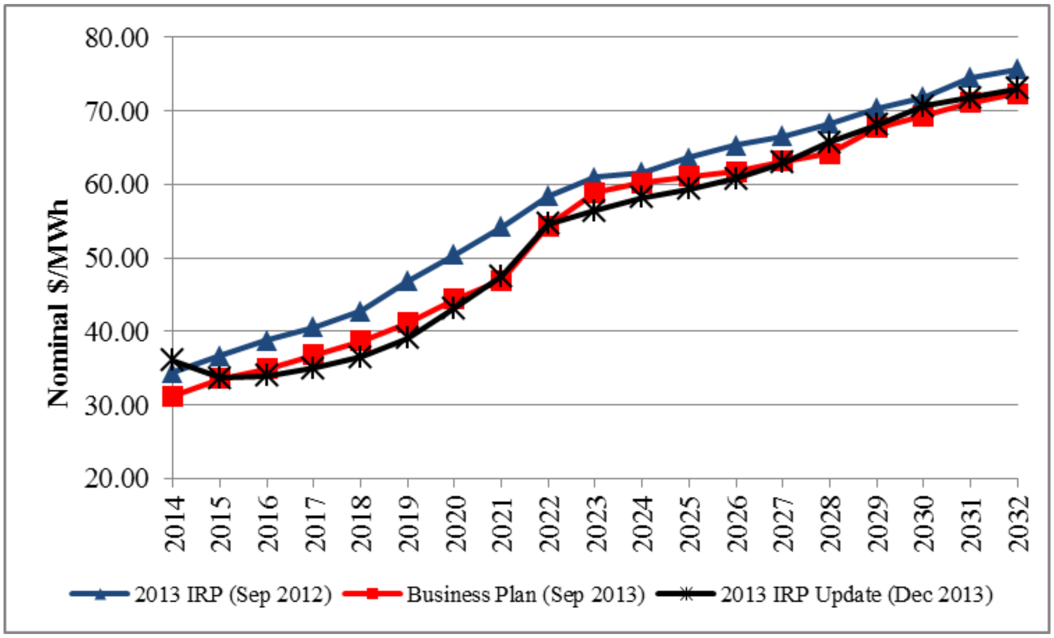
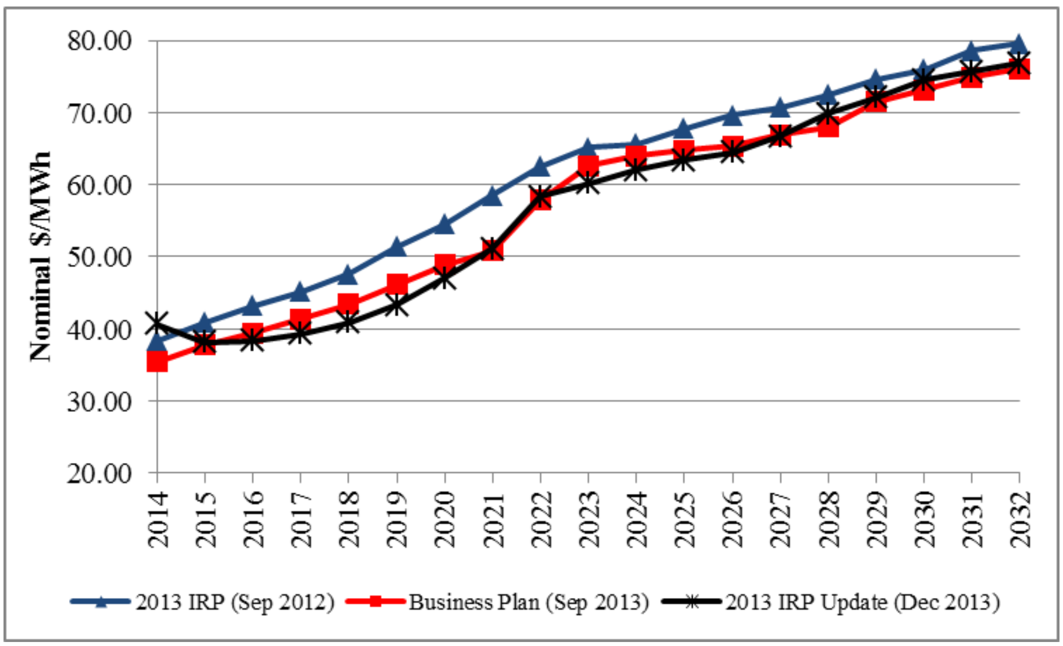


Figure 4.5 – Average Annual Heavy Load Hour Mid-Columbia Electricity Prices



Carbon Dioxide Emission Costs and Compliance

After PacifiCorp filed the 2013 IRP, President Obama issued a Presidential Memorandum in June 2013 directing EPA to issue standards, regulations, or guidelines, as appropriate that address greenhouse gas emissions from modified, reconstructed, and existing power plants. The proposed standards, regulations, or guidelines are to be issued by June 1, 2014, finalized by June 1, 2015, with implementation of regulations as proposed in SIPs required by June 30, 2016. EPA would then review the implementation plan proposed by each state, and the effective compliance dates for these standards, regulations, or guidelines would become applicable sometime thereafter.

Absent information on how EPA intends to proceed with its rule-making process, and without any information on how individual states will propose to implement those regulations through a SIP, there is currently no means to develop a specific CO_2 price assumption that accurately reflects potential CO_2 regulation. PacifiCorp's review of current third-party CO_2 price forecasts shows that despite issuance of the Presidential Memorandum, these forecasters have not materially altered either their assumed CO_2 start date or price level. In the 2013 IRP Update, PacifiCorp continues to assume a CO_2 price signal beginning 2022 at $16/ton escalating at three percent plus inflation thereafter, and expects to update its CO_2 policy assumptions and scenarios in the 2015 IRP, taking into consideration the proposed standard, regulation, or guidelines expected to be issued by EPA later this year.

Transmission Topology

The topology used in the Business Plan sensitivity and the 2013 IRP Update studies are consistent with what was used for Energy Gateway Scenario 2 in the 2013 IRP, except the changes in timing of Energy Gateway Segment D as noted in Chapter 2 of the 2013 IRP Update.

Supply-side Resources

The supply side resource costs and performance parameters did not change from the 2013 IRP, except that the costs of utility scale solar photovoltaic resources are updated based on a Company commissioned study completed by Black & Veatch in December 2013. Updated costs are summarized in Table 4.1, along with those included in the 2013 IRP. The costs of solar reduced by over 10% for both single tracking and fixed tilt.

Table 4.1 – Updated Cost of Solar Resources, 2013$ - (50 MW AC)

	2013 IRP Update			2013 IRP		
Technology	**EPC Only $/W_{AC}$**	**Owner's Costs $/W_{AC}$**	**Total (with Owner's Costs) $/W_{AC}$**	**EPC Only $/W_{AC}$**	**Owner's Costs $/W_{AC}$**	**Total (with Owner's Costs) $/W_{AC}$**
Single Axis Tracking	$2.682	$0.172	$2.854	$2.982	$0.194	$3.176
Fixed Tilt	$2.526	$0.162	$2.688	$2.770	$0.182	$2.952

For this filing, PacifiCorp performed two sensitivity studies around the performance of renewable resources and costs of the solar resources. The first sensitivity study changed the peak contribution of wind resource to 20.5%, and solar resources to 68% and 84% for fixed tilt and single axis tracking, respectively. This sensitivity study was requested by the PSCU in its order acknowledging the Company's 2013 IRP. The second sensitivity was performed using updated the costs consistent with those shown above, in addition to changes to the peak contributions consistent with those requested by the PSCU. Both sensitivities are discussed in Chapter 5.

CHAPTER 5 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used the System Optimizer (SO) capacity expansion optimization model to develop resource portfolios based on inputs and assumptions updated throughout its business planning process. Similarly, the SO model was used to develop resource portfolios for the 2013 IRP Update consistent with its most recent resource needs assessment as described in Chapter 3. As was done in the 2013 IRP, the Company devised minimum wind resource acquisition targets for renewable portfolio standards using the RPS Scenario Maker model and treated these targets as a minimum fixed resource schedule in the capacity expansion modeling. The Company also maintained the natural gas resources and the combined heat & power (CHP) resources from the 2013 IRP Preferred Portfolio. Consequently, the Business Plan resource portfolio was developed by allowing demand side management programs and front office transactions (FOTs) to balance system capacity and energy. The 2013 IRP Update study was developed by allowing for a fully optimized selection of resource alternatives. This chapter first describes the development of the wind resource addition timing, and then presents the 2013 IRP Update and Business Plan portfolios along with comparisons to the 2013 IRP Preferred Portfolio.

Wind Resources and Renewable Portfolio Standard Compliance

Renewable Energy Credit Value

Parties in Utah questioned PacifiCorp's treatment of renewable energy credits (RECs) in the 2013 IRP; as such the PSCU requested the Company address two specific issues in this IRP Update. These were the risks of relying on unbundled RECs as opposed to physical resources, and inclusion of the value of a REC as an offset to the cost of a renewable resource.

The Company expressly addressed the risk of relying on unbundled RECs in the 2013 IRP. Specifically, the determination of the preferred portfolio was made after calculating the cost and financial risk of meeting incremental renewable portfolio standard (RPS) compliance in Washington using physical resources.[6] This analysis showed that on an expected value basis, unbundled REC prices would need to exceed $51/MWh before the unbundled REC strategy would prove to be higher cost than meeting Washington RPS obligations with physical resources. Similarly, when the stochastic risk benefits of physical wind resources were factored into this analysis, PacifiCorp's study showed that unbundled REC prices would need to exceed $48/MWh for the physical supply strategy to be more cost effective. Based on its participation in the REC market, PacifiCorp does not expect unbundled REC prices to reach, let alone exceed, these levels and that pursing a physical compliance strategy would increase costs for Washington customers. In fact, PacifiCorp has already been using unbundled REC purchases to satisfy Washington RPS requirements.

[6] PacifiCorp notes that existing physical resources have been and will continue to be used to meet Washington RPS requirements. Use of unbundled RECs is planned for meeting incremental Washington RPS needs as the target grows over time.

PacifiCorp's experience in the REC market leads it to believe that it is unlikely it will be unable to purchases sufficient tradable RECs to cover its Washington and California RPS compliance obligations. As identified in the 2013 IRP Action Plan, PacifiCorp has identified the steps it will take to procure unbundled RECs required for RPS compliance, including issuance of requests for proposals (RFPs) seeking both current-year and forward-year vintage unbundled RECs. By continuing to monitor REC availability and pricing through these competitive solicitation process, PacifiCorp can readily observe potential, yet unlikely, changes in the REC market that would limit opportunities to purchase unbundled RECs as needed for the Washington RPS. Considering that PacifiCorp does not have an incremental need for Washington RPS RECs until 2016, and further considering that this incremental need can be deferred using flexible banking provisions allowed in the Washington RPS, the Company has the flexibility to pursue alternative compliance strategies, including compliance with physical supply, should circumstances change. PacifiCorp continues to assume in its 2013 IRP Update that incremental Washington RPS requirements will be met with unbundled REC purchases.

As to the inclusion of a REC value as an offset to renewable resource costs, this assumption would ascribe a monetary value that PacifiCorp could not realize, and is therefore, inappropriate as a means to justify acquiring physical renewable resources. The recommended approach is not suitable for renewable resources that are being added to the preferred portfolio for purposes of complying with a RPS. This is not practical for a load serving entity having to meet an RPS obligation, which effectively requires that a REC be "retired" when used for RPS compliance, making that REC unavailable for sale, and therefore, eliminating the ability to monetize the unbundled REC as a means to offset project costs. If a renewable resource is added for a reason other than RPS compliance, given current REC market conditions, it is not appropriate to assume REC revenues can offset the cost of the renewable project over the life of the asset. The REC market lacks transparency, and while the Company is comfortable assessing the upper limits of REC prices going forward, the lack of transparency makes it inappropriate to assume a pre-determined REC revenue stream that can offset renewable resource costs over a 25 to 30 year period. Moreover, the sale of unbundled RECs can limit the use of the underlying "green attributes" associated with the REC, limiting its potential use for meeting future environmental compliance obligations to reduce greenhouse gas emissions. PacifiCorp has not assumed a REC value as an offset to renewable resource costs in the 2013 IRP Update.

Wind Resources

Table 5.1 presents a comparison of the wind additions from the 2013 IRP Preferred Portfolio, Business Plan, and 2013 IRP Update. The projected wind capacity additions declined somewhat from the 2013 IRP to the Business Plan, and again from the Business Plan to the 2013 IRP Update. The main drivers include updated regulatory assumptions, decline in forecasted load, and an overall increase in forecasted generation from current renewable resources. The capacity additions decrease in 2024, but those decreases are partially offset by 2025 increases. As was the case in the 2013 IRP, wind resources included in the resource portfolio are not economic and are included to meet state RPS obligations.

The capacity additions in the IRP assumed implementation of a Federal RPS standard. The assumed federal RPS requirements were 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. However, since 2010, no significant activity has occurred with respect to the development of a federal renewable portfolio standard. In addition, current political environments are shifting focus from items such as the extension of federal incentives for renewables and portfolio standards to EPA's development of greenhouse gas standards. Accordingly, at this time the Company does not have a basis to make assumptions regarding any future federal renewable portfolio standard.

Table 5.1 – Wind Additions, 2013 IRP Preferred Portfolio, Business Plan, 2013 IRP Update

	Installed Capacity (MW)			
Source	Year 2024	Year 2025	Total Capacity Additions	Incremental Capacity Changes From Prior Resource Portfolio (Decrease)
2013 IRP	432	218	650	-
Business Plan	184	365	549	(101)
2013 IRP Update	184	296	480	(69)

Renewable Portfolio Standard Compliance

Table 5.2 summarizes the forecasted state annual RPS targets as defined by each state's RPS program, the forecasted annual megawatt-hour RPS requirements, and the quantity of megawatt-hours available from existing eligible renewable resources. The RPS Scenario Maker model is used to ensure compliance with RPS requirements through the planning period.

The RPS Scenario Maker model uses retail sales forecast inputs, state-specific targets, state specific banked 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 SO model to establish a least cost renewable resource mix that meets RPS requirements.

This RPS compliant wind schedule is shown above in Table 5.1. Note that acquisition of an incremental 549 MW and 480 MW of wind for the Business Plan and 2013 IRP Update respectively, is needed to comply with RPS requirements through the planning period. An overview of the RPS compliance picture for each state is provided below.

Table 5.2 – Renewable Portfolio Standard Targets, Requirements, and Initial Eligible Existing RECs by State for 2013 IRP, Business Plan, and 2013 IRP Update

2013 IRP Update

RPS Targets

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	5%	5%	5%	15%	15%	15%	15%	15%	20%	20%	20%	20%	20%	25%	25%	25%	25%	25%	25%	25%	25%
Washington	3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
California	20%	20%	22%	23%	25%	27%	29%	31%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%

RPS Requirements (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	638,939	648,264	650,556	1,967,441	1,966,953	1,975,074	1,976,830	1,980,973	2,653,488	2,651,787	2,660,538	2,672,988	2,688,662	3,357,833	3,363,691	3,369,320	3,384,188	3,381,711	3,389,942	3,397,284	3,413,507
Washington	119,857	120,716	120,255	119,200	357,241	357,579	357,674	357,526	596,920	598,724	599,577	599,718	601,399	604,676	607,344	609,217	611,984	616,059	619,714	622,616	626,152
California	156,532	154,757	167,002	178,872	192,203	206,628	221,654	236,735	252,117	251,078	250,828	250,932	251,671	250,933	250,457	250,128	251,141	251,022	251,613	251,921	253,027

Existing Qualifying Resources (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	1,856,743	1,822,669	1,923,163	2,018,394	1,802,862	1,794,795	1,785,527	1,784,907	1,768,040	1,761,360	1,806,175	1,798,875	1,769,330	1,731,728	1,687,782	1,683,305	1,672,365	1,670,734	1,593,039	1,414,134	1,250,280
Washington	104,932	106,169	125,779	89,357	89,222	88,147	87,703	87,431	85,835	85,281	84,802	84,238	83,367	82,360	82,267	82,138	82,574	82,782	82,687	83,497	59,047
California	157,756	152,507	156,753	154,865	154,692	153,028	136,793	151,747	143,444	142,463	144,745	143,812	140,236	136,264	132,712	132,029	131,853	130,977	126,439	117,604	108,847

Business Plan

RPS Targets

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	5%	5%	5%	15%	15%	15%	15%	15%	20%	20%	20%	20%	20%	25%	25%	25%	25%	25%	25%	25%	25%
Washington	3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
California	20%	20%	22%	23%	25%	27%	29%	31%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%

RPS Requirements (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	638,939	647,686	654,247	1,979,103	1,979,422	1,988,207	1,990,605	1,994,983	2,674,260	2,673,173	2,682,596	2,695,484	2,711,496	3,386,501	3,392,524	3,398,122	3,412,778	3,409,859	3,417,750	3,424,611	3,440,402
Washington	119,857	120,716	120,491	119,468	357,453	357,831	357,968	357,866	597,556	599,426	600,342	600,543	602,283	605,620	608,348	610,281	613,105	617,235	620,945	623,903	627,494
California	156,532	155,413	166,668	178,373	191,578	205,878	220,784	235,697	250,988	249,848	249,525	249,582	250,268	249,494	248,988	248,650	249,659	249,550	250,158	250,469	251,568

Existing Qualifying Resources (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	1,737,772	1,782,356	1,727,942	1,732,935	1,766,729	1,756,865	1,742,637	1,754,826	1,729,964	1,724,327	1,806,594	1,804,926	1,700,069	1,648,809	1,605,732	1,600,878	1,589,438	1,578,221	1,502,709	1,314,658	1,157,522
Washington	104,932	120,131	116,751	81,363	88,986	88,012	85,202	86,418	85,124	84,057	83,557	82,801	82,446	81,512	81,393	81,263	81,704	81,904	81,811	82,614	59,095
California	157,778	151,959	149,266	148,883	150,162	148,806	134,379	147,387	141,132	139,930	141,789	140,630	139,528	136,008	132,448	131,766	131,591	130,710	126,169	117,569	108,971

2013 IRP

RPS Targets

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	5%	5%	5%	15%	15%	15%	15%	15%	20%	20%	20%	20%	20%	25%	25%	25%	25%	25%	25%	25%	25%
Washington	3%	3%	3%	3%	9%	9%	9%	9%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
California	20%	20%	22%	23%	25%	27%	29%	31%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%

RPS Requirements (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	647,085	653,055	658,449	1,983,516	2,001,158	2,010,405	2,020,165	2,030,032	2,723,482	2,725,331	2,735,738	2,750,440	2,771,062	3,463,641	3,472,307	3,479,376	3,495,523	3,489,520	3,496,247	3,505,949	3,525,363
Washington	119,857	119,919	118,971	118,101	353,460	353,652	353,628	353,231	589,052	589,731	588,764	586,450	584,773	583,861	581,693	579,111	578,948	580,360	580,711	579,925	579,885
California	156,281	155,710	168,364	180,432	194,029	208,793	223,767	238,663	253,644	251,490	250,054	248,146	246,482	242,914	240,411	238,724	238,316	236,354	235,398	234,260	233,861

Existing Qualifying Resources (MWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Oregon	1,750,660	1,798,273	1,804,947	1,809,127	1,813,393	1,809,481	1,804,344	1,808,479	1,797,068	1,793,435	1,867,656	1,867,275	1,766,211	1,736,911	1,692,983	1,688,558	1,677,563	1,675,902	1,598,266	1,414,134	1,250,280
Washington	91,497	91,642	90,038	89,633	89,272	88,456	88,155	87,636	86,638	85,915	85,060	84,398	84,078	83,062	82,969	82,839	83,278	83,488	83,392	84,209	59,453
California	160,642	153,564	153,501	153,375	151,803	151,307	137,269	149,706	141,822	140,749	142,472	141,333	140,221	136,567	133,008	132,320	132,143	131,226	126,686	117,947	109,137

For reference, Figure 5.1 indicates how RPS compliance is forecasted to be met through 2022 using current IRP Update assumptions. Figure 5.2 shows the compliance forecast for the Business Plan. These two sets of graphs are limited to the compliance forecast for the states, as the federal RPS assumption has been dropped. For comparison purposes, Figure 5.3 has the RPS compliance forecast as included in the 2013 IRP.

Figure 5.1 – 2013 IRP Update RPS Compliance Position

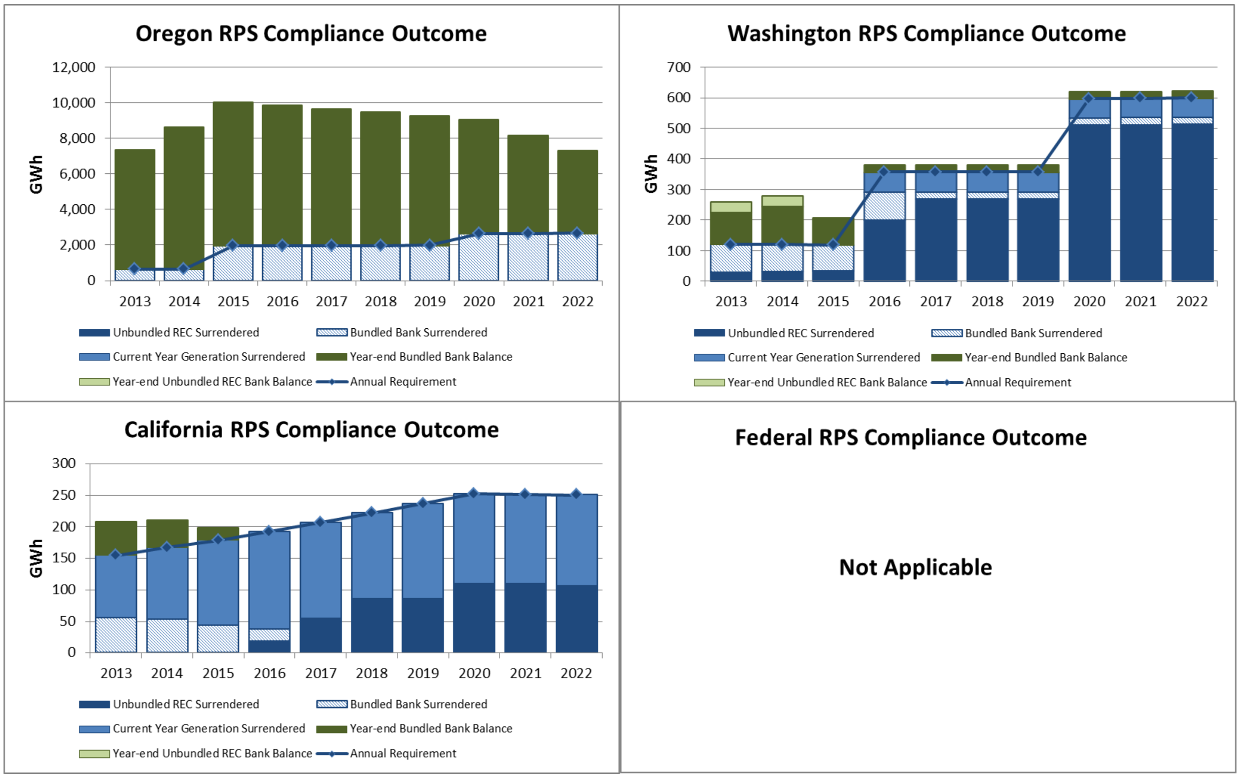


Figure 5.2 – Business Plan RPS Compliance Position

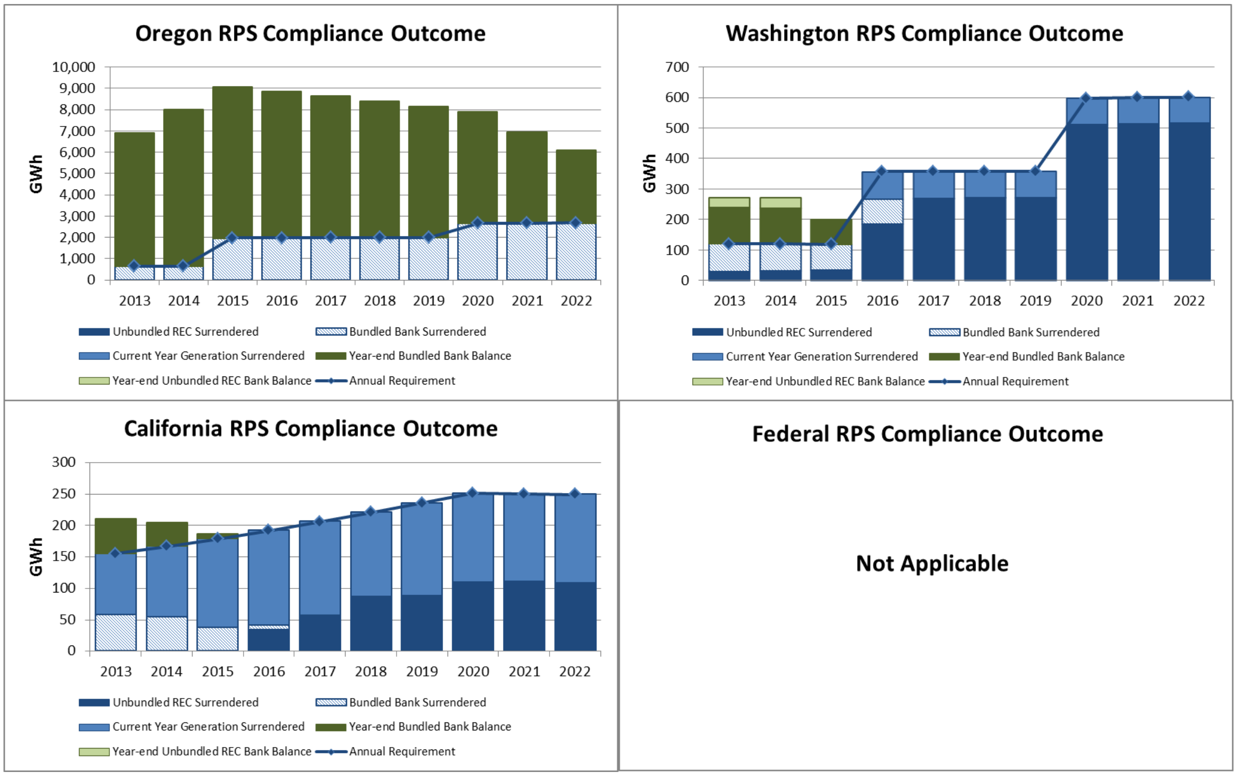
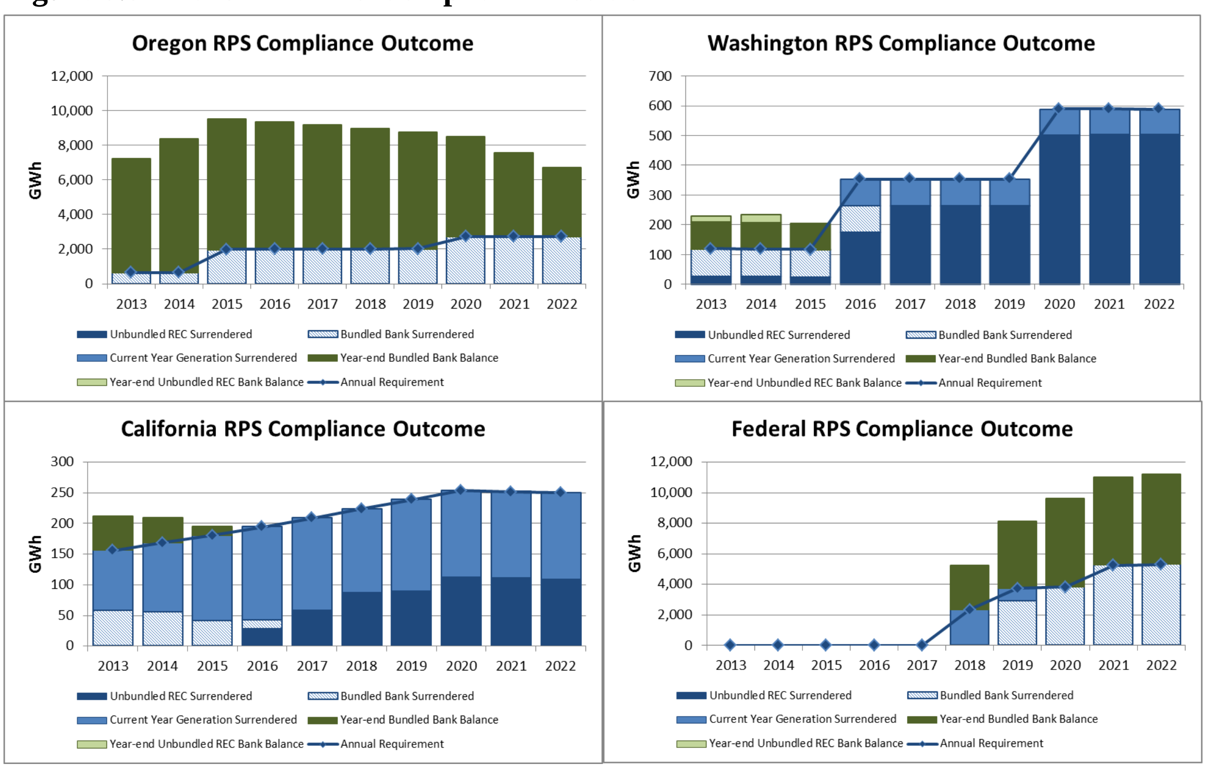


Figure 5.3 – 2013 IRP RPS Compliance Position



2013 IRP Update Resource Portfolio

The 2013 IRP Update focuses on changes that occurred after PacifiCorp filed its 2013 IRP and includes comparisons to the resource portfolio developed for the Business Plan. These primarily involve updates to load forecasts, and any additions to the Company's contract assortment.

Table 5.3 summarizes the annual megawatt capacity, timing and differences in resources for the 2013 IRP Update and 2013 IRP preferred portfolios for the comparative 10-year period of 2014 through 2023. Consistent with the reduction in resource need, driven primarily by a lower load forecast, the addition of new resources was reduced in the Business Plan and again in the 2013 IRP Update resource portfolios. This is primarily evident with reduced reliance on FOTs, and given the relatively minor changes in demand side management (DSM) resource selections, PacifiCorp has not modified its 2013 IRP Action Plan and continues to target accelerated acquisition of cost-effective energy efficiency. Outside of the first ten years, the first major thermal resource is deferred from 2024 (2013 IRP Preferred Portfolio) to 2027 (2013 IRP Update), and as discussed above, wind resource needs in the 2024-2025 timeframe have been lowered by 170 MW. Table 5.4 summarizes the 2013 IRP Update load and resource balance for 2014-2023, and Table 5.5 displays the detailed 2013 IRP Update resource portfolio through 2032.

Table 5.3 – Comparison of 2013 IRP Update with 2013 IRP Preferred Portfolio

2013 IRP Update

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	645
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	112	110	98	96	95	88	82	74	74	74	64	854
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	2	6	2	-	-	-	-	-	-	-	-	8
Renewable - Distributed Solar	7	11	14	16	17	13	14	15	15	15	15	147
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	11
Front Office Transactions *	255	445	583	701	831	931	1,027	1,261	1,042	1,098	1,210	913
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(502)	-	-		-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-		-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	338	-	-		-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-
Total	**391**	**1,218**	**534**	**814**	**944**	**1,034**	**1,123**	**1,351**	**1,132**	**1,189**	**1,290**	

Front Office Transactions in resource total are 10-year average. *

2013 IRP - Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	645
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	909
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	6
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	147
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	11
Front Office Transactions *	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,154
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	

Front Office Transactions in resource total are 10-year average. *

Difference - 2013 IRP Update Less 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	(2)	(6)	(5)	(6)	(2)	(4)	(8)	(7)	(6)	(8)	(4)	(55)
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	(2)	3	(1)	-	-	-	-	-	-	-	-	2
Renewable - Distributed Solar	-	-	-	-	(1)	(0)	-	1	-	-	-	-
Combined Heat & Power	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	(395)	(264)	(262)	(282)	(271)	(278)	(296)	(159)	(149)	(235)	(217)	(241)
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(399)**	**(267)**	**(268)**	**(288)**	**(274)**	**(282)**	**(304)**	**(165)**	**(155)**	**(243)**	**(221)**	

Front Office Transactions in resource total are 10-year average. *

Table 5.4 – 2013 IRP Update Capacity Load and Resource Balance

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	111	110	125	125	122	125	125	125	125	125
Renewable	92	82	82	82	82	82	82	81	81	79
Purchase	662	662	425	312	312	312	312	283	283	283
Qualifying Facilities	79	83	93	93	93	93	93	92	88	88
Sale	(763)	(738)	(738)	(663)	(663)	(663)	(663)	(183)	(183)	(183)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	293	511	493	615	627	584	903	650	740	798
East Existing Resources	**7,062**	**7,132**	**6,896**	**6,980**	**6,989**	**6,949**	**7,268**	**7,464**	**7,550**	**7,606**
Combined heat and Power	0	1	3	3	3	3	4	4	6	6
Front Office Transactions	0	0	0	0	64	171	101	0	0	43
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	2	4	6	8	10	12	13	15	18	20
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**2**	**5**	**9**	**11**	**77**	**186**	**118**	**19**	**24**	**69**
East Total Resources	**7,064**	**7,137**	**6,905**	**6,991**	**7,066**	**7,135**	**7,386**	**7,483**	**7,574**	**7,675**
Load	6,810	6,930	6,792	6,916	7,028	7,133	7,395	7,517	7,635	7,757
Existing Resources:										
Interruptible	(159)	(159)	(186)	(186)	(186)	(186)	(186)	(186)	(186)	(186)
Class 1 DSM	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(105)	(152)	(196)	(244)	(289)	(330)	(370)	(407)	(443)	(478)
East obligation	**6,217**	**6,290**	**6,081**	**6,157**	**6,224**	**6,288**	**6,510**	**6,595**	**6,677**	**6,764**
Planning Reserves (13%)	808	818	791	800	809	817	846	857	868	879
East Reserves	**808**	**818**	**791**	**800**	**809**	**817**	**846**	**857**	**868**	**879**
East Obligation + Reserves	**7,025**	**7,108**	**6,872**	**6,957**	**7,033**	**7,105**	**7,356**	**7,452**	**7,545**	**7,643**
East Position	**39**	**29**	**33**	**34**	**33**	**30**	**30**	**31**	**29**	**32**
East Reserve Margin	14%	13%	14%	14%	14%	13%	13%	13%	13%	13%
West										
Thermal	2,524	2,524	2,506	2,503	2,503	2,503	2,503	2,503	2,500	2,497
Hydroelectric	777	775	774	774	747	730	734	641	652	652
Renewable	38	38	38	38	38	38	38	38	21	21
Purchase	187	190	21	21	21	3	3	3	3	3
Qualifying Facilities	99	86	76	76	71	71	71	71	71	67
Sale	(306)	(207)	(157)	(156)	(156)	(157)	(157)	(153)	(100)	(102)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(293)	(512)	(493)	(616)	(629)	(586)	(905)	(651)	(740)	(800)
West Existing Resources	**3,023**	**2,891**	**2,762**	**2,637**	**2,592**	**2,599**	**2,284**	**2,449**	**2,404**	**2,335**
Combined heat and Power	1	2	2	3	3	4	4	5	5	6
Front Office Transactions	503	659	793	939	989	989	1,325	1,178	1,241	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	**504**	**661**	**795**	**942**	**992**	**993**	**1,329**	**1,183**	**1,246**	**1,331**
West Total Resources	**3,527**	**3,552**	**3,557**	**3,579**	**3,584**	**3,592**	**3,613**	**3,632**	**3,650**	**3,666**
Load	3,174	3,221	3,251	3,294	3,325	3,349	3,382	3,412	3,442	3,475
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(60)	(84)	(109)	(135)	(158)	(175)	(187)	(203)	(218)	(240)
West obligation	**3,114**	**3,137**	**3,142**	**3,159**	**3,167**	**3,174**	**3,195**	**3,209**	**3,224**	**3,235**
Planning Reserves (13%)	405	408	408	411	412	413	415	417	419	421
West Reserves	**405**	**408**	**408**	**411**	**412**	**413**	**415**	**417**	**419**	**421**
West Obligation + Reserves	**3,519**	**3,545**	**3,550**	**3,570**	**3,579**	**3,587**	**3,610**	**3,626**	**3,643**	**3,656**
West Position	**8**	**7**	**7**	**9**	**5**	**5**	**3**	**6**	**7**	**10**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	10,591	10,689	10,462	10,570	10,650	10,727	10,999	11,115	11,224	11,341
Obligation	9,331	9,427	9,223	9,316	9,391	9,462	9,705	9,804	9,901	9,999
Reserves	1,213	1,226	1,199	1,211	1,221	1,230	1,262	1,275	1,287	1,300
Obligation + Reserves	10,544	10,653	10,422	10,527	10,612	10,692	10,967	11,079	11,188	11,299
System Position	47	36	40	43	38	35	32	36	36	42
Reserve Margin	14%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 5.5 – 2013 IRP Update, Detail Portfolio

		Capacity (MW)																				Resource Totals 1/	
	Resource	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 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	368	-	-	**-**	**368**
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	834	-	-	-	-	**-**	**1,257**
	Lake Side II	-	645	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**645**	**645**
	Coal Plant Turbine Upgrades	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**2**	**2**
	Wind, Wyoming, 40	-	-	-	-	-	-	-	-	-	-	-	184	296	-	-	-	-	-	-	-	**-**	**480**
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	**184**	**296**	-	-	-	-	-	-	-	**-**	**480**
	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-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	**-**	**1**
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	74	-	-	-	-	-	-	**-**	**74**
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	**-**	**0**
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	0.2	-	-	-	-	-	-	-	**-**	**0**
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	**1**	**74**	-	-	-	-	-	-	**-**	**75**
	DSM, Class 2, ID	3	3	3	3	3	3	3	3	3	4	3	3	3	3	2	2	2	2	2	3	**28**	**51**
	DSM, Class 2, UT	63	55	50	48	49	47	44	39	40	39	30	33	30	28	26	25	23	22	21	20	**474**	**731**
	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**	**56**	**57**	**55**	**53**	**48**	**50**	**50**	**39**	**42**	**39**	**37**	**35**	**33**	**32**	**30**	**30**	**30**	**556**	**904**
	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	-	-	-	-	-	-	0.5	1.7	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	-	-	-	-	-	56	152	89	-	-	38	130	300	300	105	194	300	129	167	300	**30**	**113**
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, 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**
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	**4**	**48**	-	-	-	-	-	-	**-**	**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	**9**	**17**
	DSM, Class 2, OR	35	40	33	32	29	26	22	19	17	17	19	19	22	22	17	18	19	18	19	22	**272**	**468**
	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	**44**	**48**	**41**	**40**	**38**	**33**	**29**	**26**	**24**	**24**	**25**	**24**	**27**	**27**	**22**	**22**	**23**	**22**	**22**	**26**	**346**	**586**
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	1.45	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**2**	**2**
	Signed Contract - OR Solar	1.0	5.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7.7**	**7.7**
	FOT COB Q3	-	-	-	-	-	-	-	297	297	223	297	297	297	297	297	297	297	297	297	297	**82**	**189**
	FOT NOB Q3	10	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	**91**	**96**
	FOT MidColumbia Q3	245	345	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	**379**	**390**
	FOT MidColumbia Q3 - 2	-	-	83	201	331	375	375	375	245	375	375	375	375	375	375	375	375	375	174	180	**236**	**286**
	Existing Plant Retirements/Conversions	-	-	**(164)**	-	-	-	-	-	-	-	-	-	-	-	-	**(760)**	-	**(701)**	**(74)**	-		
	Annual Additions, Long Term Resources	**136**	**773**	**115**	**113**	**113**	**103**	**96**	**90**	**90**	**91**	**80**	**267**	**383**	**202**	**497**	**906**	**71**	**1,098**	**489**	**72**		
	Annual Additions, Short Term Resources	**255**	**445**	**583**	**701**	**831**	**931**	**1,027**	**1,261**	**1,042**	**1,098**	**1,210**	**1,302**	**1,472**	**1,472**	**1,277**	**1,366**	**1,472**	**1,301**	**1,138**	**1,277**		
	Total Annual Additions	**391**	**1,218**	**698**	**814**	**944**	**1,034**	**1,123**	**1,351**	**1,132**	**1,189**	**1,290**	**1,569**	**1,855**	**1,674**	**1,774**	**2,272**	**1,543**	**2,399**	**1,627**	**1,349**		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Business Plan Resource Portfolio

The Business Plan expansion resource portfolio is similar to the 2013 IRP Preferred Portfolio with the exception of DSM and FOTs. The DSM values are slightly different from what were in the 2013 IRP Preferred Portfolio due to updated and slightly lower load forecast, and the changes in FOTs reflect the change in resource need as described in Chapter 3.

Table 5.6 summarizes the annual megawatt capacity, timing and differences in resources for the Business Plan resource portfolio and the 2013 IRP Preferred Portfolio during the comparative ten-year period of 2014 through 2023. Major changes within the ten-year period include reduction of FOTs and DSM. Outside of the front ten-years is a reduction in wind resources by 248 megawatt in 2024, partially offset by an increase of 147 megawatts in 2025.

Table 5.7 shows the capacity load and resource balance for 2014-2023. A more detailed table of portfolio resources is provided as Table 5.8.

Table 5.6 – Comparison of Business Plan with 2013 IRP Preferred Portfolio

2014 Business Plan Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW												
	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	**645**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	117	116	103	100	96	91	89	80	79	78	64	**895**
DSM - Load Control	-	-	-	-	-	-	-	21	-	-	-	**21**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	2	6	2	-	-	-	-	-	-	-	-	**8**
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	**147**
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	**11**
Front Office Transactions *	479	516	669	797	931	1,032	1,125	1,340	1,122	1,178	1,294	**1,000**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	**338**
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-
Total	**620**	**1,295**	**625**	**914**	**1,045**	**1,137**	**1,229**	**1,457**	**1,217**	**1,272**	**1,375**	

Front Office Transactions in resource total are 10-year average. *

2013 IRP - Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW												
	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	**645**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	**909**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	**6**
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	**147**
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	**11**
Front Office Transactions *	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	**1,154**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	**338**
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	

Front Office Transactions in resource total are 10-year average. *

Difference - 2014 Business Plan Portfolio Less 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW												
	Installed Capacity, MW											10-year
Resource	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	2	(0)	(0)	(1)	(1)	(1)	(0)	(0)	(1)	(4)	(4)	**(14)**
DSM - Load Control	-	-	-	-	-	-	-	21	-	-	-	**21**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	(2)	3	(1)	-	-	-	-	-	-	-	-	**2**
Renewable - Distributed Solar	-	-	-	-	-	-	-	-	-	-	-	-
Combined Heat & Power	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	(171)	(193)	(176)	(186)	(171)	(177)	(198)	(80)	(69)	(155)	(133)	**(154)**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(171)**	**(190)**	**(178)**	**(187)**	**(172)**	**(178)**	**(198)**	**(59)**	**(70)**	**(159)**	**(137)**	

Front Office Transactions in resource total are 10-year average. *

Table 5.7 –Business Plan Capacity Load and Resource Balance

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
East										
Thermal	6,626	6,460	6,454	6,454	6,454	6,454	6,454	6,454	6,454	6,454
Hydroelectric	111	110	125	125	122	125	125	125	125	125
Renewable	92	82	82	82	82	82	82	81	81	79
Purchase	662	662	425	312	312	312	312	283	283	283
Qualifying Facilities	79	80	83	83	83	83	83	82	78	78
Sale	(738)	(738)	(738)	(663)	(663)	(663)	(663)	(183)	(183)	(183)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	353	587	578	642	603	562	906	742	825	801
East Existing Resources	**7,147**	**7,205**	**6,971**	**6,997**	**6,955**	**6,917**	**7,261**	**7,546**	**7,625**	**7,599**
Combined heat and Power	0	1	3	3	3	3	4	4	6	6
Front Office Transactions	0	0	0	63	178	282	190	0	7	138
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	2	4	6	8	10	12	13	15	18	20
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**2**	**5**	**9**	**74**	**191**	**297**	**207**	**19**	**31**	**164**
East Total Resources	**7,149**	**7,210**	**6,980**	**7,071**	**7,146**	**7,214**	**7,468**	**7,565**	**7,656**	**7,763**
Load	6,892	7,004	6,872	7,000	7,113	7,221	7,487	7,612	7,731	7,859
Existing Resources:										
Interruptible	(159)	(159)	(186)	(186)	(186)	(186)	(186)	(186)	(186)	(186)
Class 1 DSM	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)	(329)
New Resources:										
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(112)	(162)	(209)	(256)	(304)	(349)	(392)	(431)	(468)	(504)
East obligation	**6,292**	**6,354**	**6,148**	**6,229**	**6,294**	**6,357**	**6,580**	**6,666**	**6,748**	**6,840**
Planning Reserves (13%)	818	826	799	810	818	826	855	867	877	889
East Reserves	**818**	**826**	**799**	**810**	**818**	**826**	**855**	**867**	**877**	**889**
East Obligation + Reserves	**7,110**	**7,180**	**6,947**	**7,039**	**7,112**	**7,183**	**7,435**	**7,533**	**7,625**	**7,729**
East Position	**39**	**30**	**33**	**32**	**34**	**31**	**33**	**32**	**31**	**34**
East Reserve Margin	14%	13%	14%	14%	14%	13%	13%	13%	13%	13%
West										
Thermal	2,524	2,524	2,506	2,503	2,503	2,503	2,503	2,503	2,500	2,497
Hydroelectric	777	775	774	774	747	730	734	641	652	652
Renewable	38	38	38	38	38	38	38	38	21	21
Purchase	187	190	21	21	21	3	3	3	3	3
Qualifying Facilities	99	86	76	76	71	71	71	71	71	67
Sale	(306)	(207)	(157)	(156)	(156)	(157)	(157)	(153)	(100)	(102)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(353)	(586)	(578)	(642)	(605)	(564)	(906)	(742)	(827)	(803)
West Existing Resources	**2,963**	**2,817**	**2,677**	**2,611**	**2,616**	**2,621**	**2,283**	**2,358**	**2,317**	**2,332**
Combined heat and Power	1	2	2	3	3	4	4	5	6	6
Front Office Transactions	583	756	901	989	989	989	1,325	1,268	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	**584**	**758**	**903**	**992**	**992**	**993**	**1,329**	**1,273**	**1,331**	**1,331**
West Total Resources	**3,547**	**3,575**	**3,580**	**3,603**	**3,608**	**3,614**	**3,612**	**3,631**	**3,648**	**3,663**
Load	3,195	3,244	3,272	3,318	3,350	3,377	3,412	3,442	3,473	3,508
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
New Resources:										
Class 1 DSM	0	0	0	0	0	0	(21)	(21)	(21)	(21)
Class 2 DSM	(61)	(86)	(113)	(139)	(162)	(180)	(194)	(214)	(231)	(254)
West obligation	**3,134**	**3,158**	**3,159**	**3,179**	**3,188**	**3,197**	**3,197**	**3,207**	**3,221**	**3,233**
Planning Reserves (13%)	407	411	411	413	414	416	416	417	419	420
West Reserves	**407**	**411**	**411**	**413**	**414**	**416**	**416**	**417**	**419**	**420**
West Obligation + Reserves	**3,541**	**3,569**	**3,570**	**3,592**	**3,602**	**3,613**	**3,613**	**3,624**	**3,640**	**3,653**
West Position	**6**	**6**	**10**	**11**	**6**	**1**	**(1)**	**7**	**8**	**10**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	10,696	10,785	10,560	10,674	10,754	10,828	11,080	11,196	11,304	11,426
Obligation	9,426	9,512	9,307	9,408	9,482	9,554	9,777	9,873	9,969	10,073
Reserves	1,225	1,237	1,210	1,223	1,233	1,242	1,271	1,283	1,296	1,309
Obligation + Reserves	10,651	10,749	10,517	10,631	10,715	10,796	11,048	11,156	11,265	11,382
System Position	45	36	43	43	39	32	32	40	39	44
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 5.8 –Business Plan, Detail Portfolio

		Installed Capacity (MW)																				Resource Totals 1/	
	Resource	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	-	-	-	-	-	-	-	-	-	-	-	184	365	-	-	-	-	-	-	-	-	**549**
	Total Wind	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**184**	**365**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**549**
	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	-	-	-	-	**81**
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	**22**
	DSM, Class 1 Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1**	**22**	**90**	**-**	**-**	**-**	**-**	**113**
	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**	**59**
	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	6	7	8	7	7	7	7	8	**55**	**125**
	DSM, Class 2 Total	**72**	**67**	**61**	**59**	**57**	**57**	**58**	**52**	**52**	**51**	**39**	**42**	**39**	**38**	**37**	**35**	**33**	**32**	**31**	**31**	**588**	**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	-	-	-	-	56	157	250	168	-	6	122	-	44	167	298	294	300	100	273	275	**64**	**126**
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	-	-	-	-	**15**
	DSM, Class 1, WA-DLC-IRR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	**2**
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	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	-	-	-	-	**2**
	DSM, Class 1 Total	-	**-**	**-**	**-**	**-**	**-**	**-**	**21**	**-**	**-**	**-**	**-**	**-**	**-**	**17**	**23**	**9**	**-**	**-**	**-**	**21**	**70**
	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	24	21	20	19	20	22	22	22	22	22	22	22	26	26	**282**	**508**
	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**	**106**
	DSM, Class 2 Total	**45**	**49**	**41**	**41**	**38**	**34**	**31**	**28**	**26**	**26**	**25**	**27**	**27**	**28**	**28**	**26**	**26**	**26**	**30**	**30**	**360**	**632**
	OR Solar (Util Cap Standard & Cust Incentive Prgm)	1.45	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**2**	**2**
	Signed Contract - OR Solar	1.0	5.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**7.7**	**7.7**
	FOT COB Q3	-	-	-	-	-	-	-	297	297	297	297	165	297	297	297	297	297	297	297	297	**89**	**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	379	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	**398**	**399**
	FOT MidColumbia Q3 - 2	-	16	169	297	375	375	375	375	325	375	375	375	375	375	375	375	375	375	375	375	**268**	**322**
	Existing Plant Retirements/Conversions	**-**	**-**	**(164)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(760)**	**-**	**(701)**	**(74)**	**-**		
	Annual Additions, Long Term Resources	**141**	**779**	**120**	**117**	**114**	**105**	**104**	**117**	**95**	**94**	**81**	**693**	**447**	**82**	**99**	**965**	**174**	**1,158**	**78**	**258**		
	Annual Additions, Short Term Resources	**479**	**516**	**669**	**797**	**931**	**1,032**	**1,125**	**1,340**	**1,122**	**1,178**	**1,294**	**1,040**	**1,216**	**1,339**	**1,470**	**1,466**	**1,472**	**1,272**	**1,445**	**1,447**		
	Total Annual Additions	**620**	**1,295**	**789**	**914**	**1,045**	**1,137**	**1,229**	**1,457**	**1,217**	**1,272**	**1,375**	**1,733**	**1,663**	**1,421**	**1,569**	**2,431**	**1,646**	**2,430**	**1,523**	**1,705**		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Sensitivity Studies around Performance of Renewable Resources

In its order acknowledging the Company's 2013 IRP, the PSCU directed the Company to perform a sensitivity case with stochastic analysis using the capacity contribution of wind and solar resources applied to determine avoided costs in Utah. The peak contributions, represented as percentage of resource nameplate, for avoided costs are shown in Table 5.9.

Table 5.9 – Peak Contribution of Renewable Resources, sensitivity study

Filing	Wind	Solar	
		Fixed Tilt	Single Tracking
2013 IRP Update	20.5%	69%	84%
2013 IRP	4.2%	13.6%	13.6%

In addition, the Company has performed studies addressing the impact of reduced costs of solar resources while also applying the capacity contribution assumptions shown above. The updated costs of solar resources are shown in Table 5.10.

Table 5.10 – Updated Costs of Solar Resources, sensitivity study (50 MW AC)

	2013 IRP Update			2013 IRP		
Technology	EPC Only $\$/W_{AC}$	Owner's Costs $\$/W_{AC}$	Total (with Owner's Costs) $\$/W_{AC}$	EPC Only $\$/W_{AC}$	Owner's Costs $\$/W_{AC}$	Total (with Owner's Costs) $\$/W_{AC}$
Single Axis Tracking	$2.682	$0.172	$2.854	$2.982	$0.194	$3.176
Fixed Tilt	$2.526	$0.162	$2.688	$2.770	$0.182	$2.952

The Company performed sensitivity studies using the SO model to determine the impact on resource portfolio composition, and using the Planning and Risk model (PaR) to determine the performance of the portfolio against stochastic risk. The case definitions assumed for the sensitivity studies are based on Case EG2-C01, Case EG2-C07 and Case EG2-C10 as defined in the Company's 2013 IRP. The cases all relied on the Energy Gateway 2 build-out, assuming segments C, D, and G are constructed. The variable assumptions for the core cases analyzed are summarized in Table 5.11.

Table 5.11 – Core Case Definitions

Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Regional Haze
C01	Medium	Medium	Medium	None	Base	Base
C07	High	Zero	Low	State & Federal	Base	Base
C10	Medium	Medium	Medium	None	Base	Stringent

Table 5.12 is a portfolio comparison between Case EG2-C01 from the 2013 IRP and the comparable sensitivity study using the capacity contribution assumptions from Table 5.9. In the sensitivity study, the peak contributions for both existing and potential renewable resources are revised to match what are in Table 5.9. The purpose of this sensitivity study is to demonstrate

whether there would be more renewable resources selected on an economic basis if their peak contributions are assumed to be higher than what the Company assumed in the 2013 IRP. Note, with higher capacity contribution assumptions, the resource need is deferred, as evidenced by the overall reduction in resource additions. The sensitivity shows that relative to Case EG2-C01, an additional 52 megawatt Wyoming wind resource in 2024 and an additional 598 megawatt wind resource is added in 2032. No additional utility scale solar resources were added in the sensitivity, and no incremental renewable resources were added in the front ten years of the planning period.

Table 5.12 – Portfolio Comparison of Case EG2-C01 and Peak Contribution Sensitivity Study

Sensitivity Study

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	-	-	-	-	-	-	-	-	-	-	661	-	-	661	-	661	-	-	2,628
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	181
DSM - Energy Efficiency	114	111	103	100	95	90	84	80	79	81	67	70	64	65	65	61	59	58	58	58	1,562
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113	-	-	22	13	148
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	-	-	-	598	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	17	17	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	333	381	514	643	1,097	1,197	1,307	1,397	1,162	1,327	1,413	1,435	1,065	1,178	1,302	1,354	1,460	1,412	1,460	1,472	1,145
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(889)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	**473**	**1,153**	**471**	**761**	**824**	**1,301**	**1,406**	**1,492**	**1,258**	**1,425**	**1,497**	**1,573**	**1,806**	**1,259**	**1,383**	**1,446**	**1,536**	**1,628**	**1,483**	**2,157**	

Case EG2-C01

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	-	-	-	-	-	-	-	-	-	661	-	-	423	661	-	661	-	-	**3,051**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	**181**
DSM - Energy Efficiency	114	116	103	100	95	90	84	80	79	81	67	70	66	65	64	61	59	57	57	60	**1,569**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	0	-	-	102	-	-	42	-	-	113	**258**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	**22**
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**10**
Renewable - Distributed Solar	7	11	14	16	17	13	15	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	2	**22**
Front Office Transactions	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	**1,242**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	**(889)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	**(1,535)**
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**338**
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14**
Total	**790**	**1,485**	**802**	**1,101**	**1,218**	**1,317**	**1,431**	**1,523**	**1,295**	**1,438**	**1,519**	**1,599**	**1,516**	**1,638**	**1,744**	**1,393**	**1,588**	**1,632**	**1,467**	**1,685**	

Portfolio Difference

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	-	-	-	-	-	-	-	-	-	-	-	(661)	661	-	(423)	-	-	-	-	-	(423)
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	(5)	-	(0)	(0)	-	-	-	-	0	-	-	(2)	(1)	1	0	-	0	1	(3)	(7)
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	(0)	-	-	(102)	-	113	(42)	-	22	(100)	(110)
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	-	-	-	576	628
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Distributed Solar	-	-	-	0	0	0	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Heat & Power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
Front Office Transactions	(317)	(328)	(331)	(341)	(8)	(16)	(24)	(31)	(37)	(14)	(22)	196	(369)	(276)	62	(60)	(10)	(5)	(7)	-	(97)
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	(387)	-	-	-	-	-	-	387	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(317)**	**(333)**	**(331)**	**(341)**	**(395)**	**(16)**	**(25)**	**(31)**	**(37)**	**(14)**	**(22)**	**(26)**	**290**	**(379)**	**(360)**	**53**	**(52)**	**(5)**	**16**	**473**	

Table 5.13 is a comparison between Case EG2-C07 in the 2013 IRP and the sensitivity study using higher capacity contribution and updated costs of solar resources. Results of this sensitivity study show that there are no additional renewable resources added beyond what were added in the 2013 IRP Preferred Portfolio. However, the higher capacity contribution reduces resource need resulting in the elimination or deferral of other resources that were included in the 2013 IRP Preferred Portfolio.

Table 5.14 is a comparison between Case EG2-C10 in the 2013 IRP and the sensitivity study using higher capacity contribution and updated costs of solar resources. Results of this sensitivity are similar to those discussed above; however, an additional 52 megawatt Wyoming wind resource is added in 2024.

Table 5.13 – Portfolio Comparison of Case EG2-C07 and Solar Cost Sensitivity Study

Sensitivity Study

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	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	1,084	-	-	**2,575**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
DSM - Energy Efficiency	115	112	100	100	97	90	85	80	80	79	65	70	66	66	67	64	64	62	61	61	**1,582**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	77	-	47	26	**151**
Renewable - Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	**858**
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**10**
Renewable - Distributed Solar	7	11	14	17	17	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	332	381	515	631	736	831	938	1,028	793	952	1,038	992	1,154	1,266	1,389	1,431	1,457	1,216	1,237	1,342	**983**
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	**473**	**1,153**	**469**	**822**	**886**	**970**	**1,052**	**1,122**	**889**	**1,093**	**1,125**	**1,511**	**1,455**	**1,349**	**1,472**	**1,598**	**1,615**	**1,678**	**1,288**	**1,445**	

Case EG2-C07

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	-	634	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	**2,802**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	**362**
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	66	67	67	65	64	54	57	56	**1,590**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	108	-	-	-	-	**193**
Renewable - Wind	-	-	-	73	35	34	14	-	-	46	6	432	218	-	-	-	-	-	-	-	**858**
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	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	**1,205**
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**	**1,475**	**802**	**1,173**	**1,253**	**1,348**	**1,440**	**1,513**	**1,286**	**1,475**	**1,515**	**2,052**	**1,604**	**1,508**	**1,639**	**1,648**	**1,552**	**1,685**	**1,281**	**1,500**	

Portfolio Difference

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	-	-	-	-	-	-	-	-	-	-	-	(423)	-	-	-	185	-	-	-	-	**(227)**
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(181)	-	-	-	(181)	**(362)**
DSM - Energy Efficiency	-	(5)	(3)	(1)	(0)	(2)	(4)	(1)	(0)	(3)	(3)	(0)	(0)	(1)	(0)	(2)	(0)	8	5	5	**(8)**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(84)	(107)	77	-	47	26	**(41)**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Distributed Solar	-	-	0	0	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Combined Heat & Power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Front Office Transactions	(318)	(328)	(330)	(351)	(366)	(377)	(384)	(390)	(397)	(379)	(387)	(118)	(149)	(158)	(82)	55	(15)	(15)	(44)	96	**(222)**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	**(318)**	**(322)**	**(333)**	**(351)**	**(367)**	**(379)**	**(388)**	**(391)**	**(397)**	**(382)**	**(390)**	**(541)**	**(149)**	**(159)**	**(167)**	**(50)**	**62**	**(7)**	**7**	**(54)**	

Table 5.14 – Portfolio Comparison of Case EG2-C10 and Solar Cost Sensitivity Study

Sensitivity Study

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	-	-	-	-	-	-	-	-	-	-	661	-	-	661	-	661	-	-	**2,628**
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	**181**
DSM - Energy Efficiency	114	111	103	100	95	90	84	80	79	81	67	70	64	65	65	61	59	58	58	58	**1,562**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113	-	-	22	13	**148**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	-	-	-	598	**650**
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**10**
Renewable - Distributed Solar	7	11	14	17	17	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	333	381	514	643	1,097	1,197	1,307	1,397	1,162	1,327	1,413	1,435	1,065	1,178	1,302	1,354	1,460	1,412	1,460	1,472	**1,145**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(889)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	**(1,535)**
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**338**
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14**
Total	**473**	**1,153**	**471**	**761**	**824**	**1,301**	**1,406**	**1,492**	**1,258**	**1,425**	**1,497**	**1,573**	**1,806**	**1,259**	**1,383**	**1,446**	**1,536**	**1,628**	**1,483**	**2,157**	

Case EG2-C10

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	-	661	-	368	**2,758**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	91	181	172	103	181	-	-	**728**
DSM - Energy Efficiency	119	117	103	100	96	91	89	81	82	81	68	70	69	70	65	61	63	62	61	59	**1,609**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	20	155	39	-	-	6	7	-	13	**239**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**10**
Renewable - Distributed Solar	7	11	14	16	17	13	15	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	4	1	1	**25**
Front Office Transactions	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	**1,262**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	**(889)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	**(1,535)**
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**338**
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**14**
Total	**791**	**1,482**	**797**	**1,097**	**1,214**	**1,311**	**1,425**	**1,512**	**1,285**	**1,425**	**1,506**	**1,542**	**1,745**	**1,687**	**1,708**	**1,621**	**1,659**	**1,633**	**1,455**	**1,929**	

Portfolio Difference

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	-	-	-	-	-	-	-	-	-	-	-	-	238	-	-	-	-	-	-	(368)	(130)
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	(91)	(181)	(172)	(103)	-	-	-	(547)
DSM - Energy Efficiency	(5)	(5)	(0)	(0)	(1)	(1)	(5)	(1)	(3)	-	(1)	(1)	(5)	(5)	(0)	0	(4)	(5)	(3)	(2)	(47)
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	(20)	(155)	(39)	-	113	(6)	(7)	22	0	(92)
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	-	-	-	598	650
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Distributed Solar	-	-	-	0	0	0	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined Heat & Power	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	-	(0)	(2)	(0)	-	(3)
Front Office Transactions	(313)	(324)	(326)	(336)	(2)	(9)	(13)	(19)	(24)	-	(8)	-	(403)	(292)	(143)	(116)	(10)	8	9	-	(116)
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	(387)	-	-	-	-	-	-	-	387	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(318)**	**(329)**	**(326)**	**(336)**	**(390)**	**(10)**	**(19)**	**(20)**	**(27)**	**-**	**(9)**	**31**	**62**	**(427)**	**(324)**	**(175)**	**(123)**	**(6)**	**28**	**229**	

At the request of the PSCU, a Planning and Risk (PaR) study was completed on the Case EG2-C07 sensitivity that assumes higher capacity contribution inputs for wind and solar resources (i.e. the sensitivity resource portfolio shown in Table 5.12). Table 5.15 compares the risk-adjusted PVRR between Case EG2-C07 and the sensitivity case.

Table 5.15 – Comparison of Risk-Adjusted PVRR between Cases EG2-C07 and the Capacity Contribution Sensitivity

Case	CO2 Tax Scenario			
	Zero	Medium	High	Average
EG2-C07	$28,621	$32,679	$39,149	$33,483
Capacity Contribution Sensitivity	$28,587	$32,710	$39,340	$33,546

CHAPTER 6 – ACTION PLAN STATUS UPDATE

This chapter provides an update to the 2013 IRP Action Plan. The status for all action items is provided in Table 6.1 below.

Related to the Action Plan is the Acquisition Path Decision Mechanism, included as Table 9.2 in the 2013 IRP. The PSCU noted that this was a "very useful table." The acquisition path analysis focused 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, there were potential ramifications to both short-term (2013-2022) and long-term (2023- 2032) resource strategies. The PSCU encouraged expansion of the table going forward.

The analysis contained herein looked at updates as included in Chapter 3 (load); and Chapter 4 (modeling updates). Specific updates were provided for gas costs, solar costs and capabilities, as well as specific resources. Sensitivities focused on the changes in solar cost and capabilities. Overall with all of the updates, the major finding is that resource acquisitions are pushed further out, mainly due to the decline in load forecasts.

For the 2015 IRP PacifiCorp will work with Stakeholders on more fully developing the acquisition path decision mechanism. This will incorporate input for variables to include, as well as potential triggering events to examine. There will be a robust look at impacts on both near- and long-term acquisition strategies.

Table 6.1 – IRP Action Plan Status Update

Action Item	Activity	Status
1a. Renewable Resource Actions -Wind Integration	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.	The wind integration study will be updated as part of the 2015 IRP process.
1b. Renewable Resource Actions - Renewable Portfolio Standard Compliance	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. 1. 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. 2. 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. 3. Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio	1. The Company issued an RFP on August 14, 2013. While there were a number of offers received, none were compelling from a price/structure perspective. Furthermore, when issued, the Company did not see a need for RECs until 2016. There will be another RFP issued prior to year-end 2014. Results will be discussed in the 2015 IRP. 2. The Company issued an RFP on December 31, 2012 with bids due January 15, 2013. A numbers of offers were selected that met matched needs and specific pricing criteria. A new RFP is planned for issuance prior to year-end 2014. 3. The Company issued an RFP on March, 14, 2014 for California-eligible RECs. Bids were due March 28, 2014; results of the RFP will be incorporated in the 2015 IRP.

Action Item	Activity	Status
	standard obligations.	
1c. Renewable Resource Actions - Renewable Energy Credit Optimization	On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.	The Company issued a total of five reverse RFPs to sell RECs in calendar 2013. To date in 2014 the Company has issued one RFP. Three more RFPs, one per quarter, are anticipated for the remainder of the year.
1d. Renewable Resource Actions – Solar	1. 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. 2. 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.	1. The Company issued a solar RFP on April 30, 2013. The final selection of two solar PV projects was completed on October 4, 2013. 2. PacifiCorp hired Black & Veatch in October 2013 to provide a report with updated market information on current EPC costs for both 5 MWac and 50 MWac single axis tracking and fixed tilt solar PV systems at selected locations. The study included Lakeview, OR and three Utah locations, Salt Lake City, Milford, and Veyo. Capital and O&M costs, as well as performance parameters were updated. See also Chapter 4 – Supply-Side Resources section.
1e. Renewable Resource Actions - Capacity Contribution	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.	The PLCC method of calculating capacity contribution for wind and solar resources will be tested in the 2015 IRP.
2a. Distributed Generation Actions - Distributed Solar	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	The Company continues to pursue solar opportunities as approved in Docket No. 11-035-104. This will include increases of 500 kW for residential customers per year through 2017. Initial evaluation report is to be filed in June

Action Item	Activity	Status
	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.	2014 with the Utah Commission.
2b. Distributed Generation Actions - Combined Heat & Power (CHP)	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.	See Appendix B for the Executive Summary of the CHP study.
3a. Firm Market Purchase Actions - Front Office Transactions	Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. 1. Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations. **2.** 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.	1. The Company plans to continue seeking procurement through multiple means, including consideration of periodic market RFPs throughout 2014. Additional bilateral negotiations will occur where there are opportunities for economic power purchases. 2. Since filing the IRP the Company has executed a purchase transaction for 25 MW of firm, heavy-load-hour energy for July-September, 2014. This resulted following an RFP in accordance with Washington

Action Item	Activity	Status
		regulatory requirements.
4a. Flexible Resource Actions - 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.	The Company is developing an energy imbalance market with the California Independent System Operator to further optimize existing resources resulting in reduced costs for customers. PacifiCorp filed EIM tariff changes with FERC on March 25. The go-live date for the energy imbalance market is scheduled for October 1, 2014. Additionally, the Company continues to follow and support the Northwest Power Pool effort in developing a security constrained economic dispatch tool among other efforts.
5a. Hedging Actions 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.	An initial workshop was held on October 29, 2013. Parties also provide comments in early December. Additional meetings were held with Utah Office of Consumer Services (OCS) and Utah Department of Public Utilities (DPU) in January, 2014. The Company continues to work with stakeholders to implement some of the feedback received.
6a. Plant Efficiency Improvement Actions	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. 1. 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. 2. Prior to initiating modeling efforts for the 2015 IRP,	1. The Company has completed a multi-plant analysis of potential energy conservation opportunities at wholly owned generation facilities. The "Energy Analysis Report" is included as Appendix C. 2. Total Resource Cost Test methodology was presented and explained to the Washington I-937 Advisory Group and accepted with no objections noted in the WUTC's order approving the Company's 10-year

Action Item	Activity	Status
	determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures. 3. 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.	conservation potential and 2014-2015 biennial conservation target, effective Jan. 1, 2014. This methodology will be the basis for analysis in the 2015 IRP. 3. As stated above, the Company will present to IRP stakeholders the analysis methodology presentation used in Washington I-937. This same methodology will be proposed as the 2015 IRP TRC test methodology.
7a. Demand Side Management (DSM) Actions - 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. 1. 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. 2. Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon. a) Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. b) Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014.	• 2013 preliminary results of 590 GWh represent 41 and 31 percent respectively of the 1,425 – 1,876 GWh three year range and 122 percent of planned 2013 targeted resources. 1. The 24 month pilot program was implemented in August 2013. Expansion will be dependent on pilot results and if appropriate included as an action item in the 2015 IRP Action Plan. 2(a) The company filed an enhanced consolidated program for business customers in May 2013. The Utah Commission approved the changes effective July 1, 2013. 2(b) The Company filed an enhanced consolidated program for business customers in November 2013. The

Action Item	Activity	Status
	c) Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.	Washington Commission approved the changes effective January 1, 2014. 2(c) The Company plans to file an enhanced consolidated program for business customers in Wyoming in April 2014 and California and Idaho in Q2 2014.
	3. 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.	3. Draft statement of work is complete. RFP to select vendor to perform the evaluation will be released in March 2014.
	4. Increase acquisitions from business customers through prescriptive measures by expanding the "Trade Ally Network". a) Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013.	4. A contract amendment with the Company's trade ally coordinator to expand the Trade Ally Network was executed August 2, 2013. The change (1) increased Trade Ally activities in training and recruitment, (2) extended work related to Utah's evaporative cooling initiative, and (3) emphasized collection of actionable market data. The end result is to implement a targeted customer outreach and engagement process with the objective of increasing participation and increasing program savings.
	5. 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.	5. Contracts were finalized with two small to mid-market third-party administrators specializing in business customer project facilitation February 25, 2014. These new contracts will increase marketing, outreach and will manage comprehensive custom projects for small to mid-market customers.

Action Item	Activity	Status
	6. 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. a) Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. b) Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. c) Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.	6(a) Revisions to the existing wattsmart Business program were previewed with Utah's DSM Advisory Committee in December 2013. The revisions will add program measures including evaporative pre-cooler retrofit, demand-controlled commercial kitchen ventilation and others. Updates are also planned for existing typical upgrade measures. Contracting for the direct install (small business lighting offer) is complete and program design work is underway. An amendment to the refrigerator/freezer recycling program vendor agreement is also underway. The Company intends to file the above mentioned program changes to the Utah program in April 2014. 6(b) Many of the proposed additions in Washington were part of the wattsmart Business filing that became effective January 1, 2014. Contracting for the direct install (small business lighting offer) is complete and program design work is underway. A meeting was held with Washington's DSM advisory group in February 2014, to preview the direct install (small business lighting) program. An amendment to the refrigerator/freezer recycling program vendor agreement is also underway. The Company filed the

Action Item	Activity	Status
		changes for the refrigerator/freezer recycling program with Washington in March 2014. The changes for the direct install (small business lighting offer) will be filed by June 2014. 6(c) Work for Wyoming, California, and Idaho programs is progressing. In Wyoming, the enhanced measures and incentives and expansion of the refrigerator/freezer recycling program will be filed in April 2014, with the direct install (small business lighting) program filed in June 2014. In California, the enhanced measure and incentives, direct install (small business lighting) program, and the expanded refrigerator/freezer recycling program will be filed in April 2014. In Idaho, the enhanced measure and incentives, direct install (small business lighting) program, and the expanded refrigerator/freezer recycling program will be filed in June 2014.
	7. 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	7(a) Held meetings with program vendor to scope Utah expansion in January 2014 with options presented to the Utah Steering Committee on February 12, 2014. Company is conducting additional analysis based on feedback from the Steering Committee. 7(b) Have not found a state that both qualifies

Action Item	Activity	Status
	System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014.	and is receptive to the commercial pilot at this point however there are ongoing discussions. 7(c) Work is ongoing with expansion options presented to the Washington Advisory Committee in February 2014. Company is conducting additional analysis based on feedback from the Advisory Committee. The Company is working with the program vendor to review program applicability for expansion to Idaho and Wyoming.
	8. Increase acquisition of residential DSM resources: a) Implement cost effective direct install options by the end of 2013. b) Expand offering of "bundled" measure incentives by the end of 2013. c) Increase qualifying measures by the end of 2013. d) Review and realign incentives: Utah schedule is 1st quarter 2014 e) Review and realign incentives: Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014 f) Review and realign incentives: Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014	8(a) A residential direct install (direct distribution of energy savings kits) RFP was issued with responses received January 2014. Kits will be available to customers in Q2 2014 as the addition of the kit measures are approved in each state. Additional programs targeting direct install measures for electrically heated manufactured homes are available in Washington and will be available in Idaho, California, Utah and Wyoming in Q2 2014. 8(b) Incentives encouraging customers to install bundles of weatherization (i.e. insulation, windows) and heating and cooling equipment (i.e. central air conditioners, heat pumps) were added in Idaho in September 2012, Utah in November 2012 and Washington in January 2014. Review

Action Item	Activity	Status
		is currently underway in California and Wyoming. 8(c) Measure updates were made in Washington effective with the January 1, 2014 program changes. Updated residential measures were part of the noticed changes in Idaho in February 2014. Work is underway with notices or filings planned to update residential measures and incentives for California and Utah by April 2014 and in Wyoming in June 2014. 8(d) Work is ongoing with filing planned for April 2014 for residential measures and incentives. 8(e) Work is complete with realigned incentives available in Washington January 1, 2014. 8(f) Work is ongoing with updated residential measures noticed in Idaho in February 2014 and notices or filings planned for California and Utah by April 2014 and Wyoming in June 2014.
	9. Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013.	9. The Company is working with our appliance recycling vendor on operational logistics of an expanded refrigerator/freezer recycling program. Changes were previewed with the Utah Steering Committee and Washington Advisory Committee in February 2014. Planned filing dates in each state are detailed above in action item 6.

Action Item	Activity	Status
	10. 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. 11. Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources. 12. 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.	10. Company met with the ETO in September 2013 to review Oregon's 2014 funding requirements, including funding that might be necessary to pursue energy efficiency resources beyond the 2013 IRP's 2014 target. Following the meeting the ETO revised their year-end 2013 funding position and 2014 incremental energy efficiency forecast and determined they had sufficient funding available for 2014 activities. The OPUC was notified in November, 2013 of the funding position. A revised funding agreement between the Company and the ETO was executed in February 2014. 11. The Class 2 DSM decrement study based on accelerated acquisition of DSM resources is included as Appendix D. 12. Analysis is ongoing.
7b. Demand Side Management (DSM) Actions - 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.	The Company has filed proposed tariffs with the OPUC. Assuming Commission approval, customers will be informed of program, and offered opportunity to sign up. The target date for beginning the pilot program is June 1, 2014.
8a. Coal Resource Actions - Naughton Unit 3	1. Continue permitting and development efforts in support of the Naughton Unit 3 natural gas	1. In its action on January 10, 2014, the EPA was in favor of the natural gas conversion on

Action Item	Activity	Status
	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. 2. 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. 3. Issue an RFP for engineering, procurement, and construction (EPC) of the Naughton Unit 3 natural gas retrofit as required supporting compliance with the conversion date that will be established during the permitting process.	Naughton Unit 3, but couldn't take action because this was not included in the WY regional haze SIP and related documents. The Company met with the Wyoming Department of Environmental Quality: Air Quality Division and WY SIP and related document modifications are now in progress. 2. RFP was issued on December 23, 2013. As of March 14, 2014 the RFP was suspended. PacifiCorp will reevaluate its natural gas transportation procurement alternatives following pending resolution of the on-going best available retrofit technology permit amendment process for Naughton Unit 3. 3. A tentative technical evaluation of the EPC RFP proposals was completed. Work to continue the RFP evaluation has been suspended until early 2016.
8b. Coal Resource Actions - Hunter Unit 1	Complete installation of the baghouse conversion and low NOX burner compliance projects at Hunter Unit 1 as required by the end of 2014.	Work is ongoing with substantial completion of the project anticipated by the end of August 2014.
8c. Coal Resource Actions - 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.	Received Certificate of Public Convenience and Necessity from Idaho, Wyoming and Utah and a full Notice to Proceed. Project evaluation is in progress.
8d. Coal Resource Actions - Cholla Unit 4	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	Evaluation is ongoing. See Chapter 2 under the Resource Update section for more information.

Action Item	Activity	Status
	in the 2013 IRP Update.	
9a. Transmission Actions - System Operational and Reliability Benefits Tool (SBT)	60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). 1. 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. 2. 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.	On June 28, 2013, an email was sent from the IRP Mailbox to the IRP participant distribution list soliciting stakeholder participation on the SBT workgroup. The first SBT workgroup kick-off workshop was held on July 29, 2013. PacifiCorp transmission established an email mailbox for SBT correspondence and a webpage. Notices of workshops and presentation materials are posted on the "Transmission SBT" webpage. Workshops were held with interested Stakeholders on July 29, 2013, August 26, 2013, September 17, 2013, (with an optional make-up webinar on September 30), and November 20, 2013. 1. Evaluation is ongoing. See Chapter 2 under Gateway West project update for more information. Given the delay in the in-service dates and the continued refinement on the SBT as a result of the stakeholder process, PacifiCorp has not included a sub-segment SBT analysis for Segment D in the 2013 IRP Update. 2. PacifiCorp will continue to refine the SBT in preparation for the 2015 IRP.
9b. Transmission Actions - Energy Gateway Permitting	Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: 1. Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. 2. Segment D, E, and F, continue to support the federal	1. PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. 2. A draft EIS for Segment F for the Gateway South project was received in February

Action Item	Activity	Status
	permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. 3. Segment H Cascade Crossing, complete benefits analysis in 2013. 4. 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.	2014. 3. As noted in the November 26, 2013, Oregon IRP Reply Comments, PacifiCorp had a memorandum of understanding with Portland General Electric (PGE) with respect to the development of Cascade Crossing that terminated by its own terms and further discussions with PGE on Cascade Crossing as an option have been ended. Thus, no benefits analysis will be completed. 4. PacifiCorp continues to support the Boardman to Hemingway project consistent with the project Joint Permit Funding Agreement. PacifiCorp has participated in the permitting process by providing review and comment of cost, scope and schedule of the project. As a participant in the project PacifiCorp continues to collaborate with Idaho Power in the permitting process providing guidance of activities and plans associated with the permitting phase of the project.
9c. Transmission Actions - Sigurd to Red Butte 345 kilovolt Transmission Line	Complete project construction per plan.	Construction began in May, 2013. As of February 2014, 69% of the total foundations, and 53% of the total 345 kV lattice towers structures are complete.
10a. Planning Reserve Margin Actions	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	An updated analysis for planning reserve margins will be completed in 2015 IRP.

Action Item	Activity	Status
	for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.	
11a. Planning and Modeling Process Improvement Actions - Modeling and Process	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.	The Company sent an email to stakeholders on July 23, 2013 to determine stakeholder availability. Thereafter, a meeting was held on September 23, 2013to discuss potential improvements. Additionally, Stakeholders were able to provide written comments up to October 17, 2013. The 2015 IRP, and associated process, will incorporate much of the Stakeholder feedback.
11b. Planning and Modeling Process Improvement Actions - Cost/Benefit Analysis of DSM Resource Alternatives	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.	DSM resources will be thoroughly studied in the 2015 IRP.

APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 3 represents the data used for capacity expansion modeling, and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). To arrive at the retail sales forecast, the initial load forecast is reduced by total Class 2 DSM as well as line losses. Table A.1 shows the retail sales forecast by state that is consistent with the 2013 IRP Update load forecast. Table A.2 shows the change in the load forecast as compared to the 2013 IRP.

Table A.1 – 2013 IRP Update Annual Retail Sales Forecast in Megawatt-hours by State

Year	OR	WA	CA	UT	WY	ID	Total
2014	13,011,121	3,971,579	769,597	22,860,795	9,705,269	3,389,170	53,707,529
2015	13,116,271	3,967,117	767,691	23,671,994	9,877,707	3,402,445	54,803,225
2016	13,113,018	3,979,083	768,813	24,536,991	10,049,251	3,421,656	55,868,812
2017	13,167,161	3,969,219	765,290	24,802,309	10,147,190	3,431,597	56,282,766
2018	13,178,870	3,975,811	764,323	25,076,147	10,257,657	3,443,919	56,696,727
2019	13,206,484	3,983,129	763,662	25,421,246	10,371,679	3,457,402	57,203,602
2020	13,267,439	3,999,854	763,991	26,333,407	10,507,412	3,474,599	58,346,703
2021	13,258,936	3,994,501	760,844	26,654,633	10,572,081	3,483,313	58,724,307
2022	13,302,688	4,001,736	760,086	27,076,817	10,663,730	3,497,362	59,302,419
2023	13,364,939	4,016,918	760,400	27,602,041	10,764,257	3,516,168	60,024,723
Average Annual Growth Rate for 2014-2023							
2014-2023	**0.30%**	**0.13%**	**-0.13%**	**2.12%**	**1.16%**	**0.41%**	**1.24%**

Table A.2 – Change in Annual Retail Sales Forecast in Megawatt-hours by State compared to the 2013 IRP

Year	OR	WA	CA	UT	WY	ID	Total
2014	(156,999)	27,583	(4,491)	(455,637)	(16,052)	(41,110)	(646,705)
2015	(117,117)	27,720	(4,701)	279,644	(16,852)	(54,378)	114,315
2016	(229,875)	26,734	(5,138)	901,029	(25,728)	(68,456)	598,566
2017	(221,364)	26,049	(5,774)	859,171	(36,059)	(71,242)	550,782
2018	(259,135)	22,109	(7,449)	819,281	(50,663)	(79,555)	444,587
2019	(293,604)	18,755	(8,720)	856,911	(57,516)	(83,734)	432,093
2020	(322,604)	16,200	(10,022)	1,419,892	(70,559)	(90,002)	942,904
2021	(350,931)	15,136	(9,465)	1,528,901	(86,645)	(86,721)	1,010,274
2022	(363,139)	13,250	(8,849)	1,644,430	(104,116)	(87,909)	1,093,666
2023	(378,659)	11,100	(8,136)	1,781,790	(123,375)	(85,636)	1,197,082

Tables A.3 shows the retail sales forecast by class that is consistent with the 2013 IRP Update load forecast. Table A.4 is the change in the retail sales forecast as compared to the 2013 IRP.

Table A.3 – System Annual Retail Sales Forecast in Megawatt-hours by Class

Year	Residential	Commercial	Industrial	Irrigation	Lighting	Public Authority	Total
2014	15,425,806	17,252,544	19,346,275	1,262,775	143,080	277,050	53,707,529
2015	15,419,299	17,578,512	20,126,314	1,262,009	143,090	274,000	54,803,225
2016	15,503,658	17,865,986	20,819,565	1,261,233	143,630	274,740	55,868,812
2017	15,520,233	18,102,730	20,982,242	1,260,301	143,260	274,000	56,282,766
2018	15,607,006	18,266,895	21,146,431	1,259,066	143,330	274,000	56,696,727
2019	15,709,357	18,405,178	21,413,865	1,257,813	143,390	274,000	57,203,602
2020	15,814,139	18,606,427	22,250,818	1,256,749	143,830	274,740	58,346,703
2021	15,866,229	18,704,796	22,480,323	1,255,459	143,500	274,000	58,724,307
2022	15,982,478	18,865,953	22,782,271	1,254,177	143,540	274,000	59,302,419
2023	16,126,149	19,095,913	23,131,650	1,253,411	143,600	274,000	60,024,723
Average Annual Growth Rate for 2014-2023							
2014-2023	0.49%	1.13%	2.01%	-0.08%	0.04%	-0.12%	1.24%

Table A.4 – Change in System Annual Retail Sales Forecast in Megawatt-hours by Class Compared to the 2013 Integrated Resource Plan

Year	Residential	Commercial	Industrial	Irrigation	Lighting	Public Authority	Total
2014	(465,322)	(52,058)	(149,066)	17,761	1,430	550	(646,705)
2015	(541,943)	(826)	639,445	17,630	1,370	(1,360)	114,315
2016	(615,709)	9,042	1,186,215	17,489	1,430	100	598,566
2017	(657,851)	65,756	1,123,761	17,647	1,430	40	550,782
2018	(713,482)	88,712	1,050,177	17,300	1,450	430	444,587
2019	(758,034)	119,254	1,051,546	17,137	1,460	730	432,093
2020	(817,649)	153,562	1,587,063	16,888	1,450	1,590	942,904
2021	(823,357)	190,011	1,624,571	16,519	1,450	1,080	1,010,274
2022	(838,930)	235,713	1,678,009	16,233	1,450	1,190	1,093,666
2023	(861,821)	280,156	1,759,975	16,053	1,450	1,270	1,197,082

The change in the retail sales forecast is driven by a decrease in residential loads, due to increases in energy efficiency and slowing growth in central air-conditioning saturation, and an increase in commercial and industrial loads due to changes in self-generation assumptions as well as continued economic recovery.

APPENDIX B – COMBINED HEAT AND POWER EXECUTIVE SUMMARY

Executive Summary

Action Item 2b in the 2013 IRP Action Plan states that PacifiCorp will pursue combined heat and power (CHP) opportunities primarily through the Public Utilities Regulatory Policies Act (PURPA) qualifying facility (QF) contracting process and states that the Company will complete a market analysis of combined heat & power (CHP) opportunities in the 2013 IRP Update. This appendix summarizes CHP opportunities consistent with Action Item 2b. This study covers opportunities across PacifiCorp's jurisdictions with a focus on PacifiCorp's western balancing authority area covering the states of Oregon, California and Washington due to available woody biomass fuel supply across those states. Among these states, Oregon is the most progressive and supportive of the development of biomass CHP projects with specific state initiatives and task forces to encourage the development of biomass generation.

The use of biomass across PacifiCorp's territory to generate electrical power has stagnated as a result of the decline in home construction caused by the recession and uncertainty related to the control of federal forestland for harvesting. The reduction in wood products production due to mill closures has reduced the availability of lower cost and clean woody biomass fuel for thermal and power generation as well as the thermal processing need that supports the base load operation of a steam turbine for power generation. In addition, changing market value and conditions for environmental attributes under the available renewable portfolio standards (RPS), decreasing avoided cost prices for QF regulation, and reduced or uncertainty around tax credits or incentives in the western states served by PacifiCorp have contributed to a pull-back by independent developers of biomass CHP facilities as well as the forest products businesses whose core strengths are the management and acquisition of timber for production as well as supply of energy for use on-site or sale to the electric utility. Results of this evaluation suggest that the Company should continue being responsive to independent or customer developed new generation opportunities through PURPA projects and assisting those developments on their decisions as they determine the use of the generation for off-setting on-site load or selling to the utility. The Company should also continue to participate with organizations in their effort to develop the appropriate legislative, governmental and regulatory incentives for biomass projects within the Pacific Northwest.

Background

Biomass energy is derived from four distinct energy sources: garbage, wood, waste, and landfill gases. Of these four fuels, garbage and landfill gas are generally not applicable as a CHP and the most prevalent in PacifiCorp's territory is the use of woody biomass.

Table B.1 summarizes PacifiCorp's existing QF power purchase agreements by state that are biomass and operate as CHP.

Table B.1 – PacifiCorp's existing Biomass QF Power Purchase Agreements by State.

State	Fuel	Projects	Capacity
CA	Wood	2	10.01
ID	Dairy waste (Methane)	1	1.70
OR	Wood	5	70.03
OR	Dairy and plant waste (Methane)	5	10.32
UT	Methane	1	0.05
WA	Methane	1	1.20
	TOTAL CHP[7]	**15**	**93.31**

Findings

There are two major fuel sources for biomass power generation, mill waste and forest thinnings. A minor, but growing, source is urban waste wood which is generally a source procured by forest products firms and is treated in this report as inclusive with mill waste.

Mill Waste

Forest products manufacturing produces waste including bark, sawdust and planer shavings. Chips are sold to pulp mills. Mill waste is consumed by plants to produce steam for internal use. Table B.2 summarizes the existing, proposed and potential biomass generation on PacifiCorp's system based on the four generation methods. These generation plants are fueled mainly by mill waste, either generated internally or purchased, and to a much smaller extent, fuel purchases in the market (i.e., urban wood waste). No projects were found on PacifiCorp's system in Idaho. Of the existing projects below, PacifiCorp is the purchaser of the output from the plants as QFs and owns the turbine asset at Georgia Pacific in Camas Washington. All are directly interconnected to PacifiCorp's transmission system. Approximately 114 MW are currently under contract to PacifiCorp or self-supplying their load. More and more QFs are moving to self-supply of their load first and selling excess due to the price differential between retail rates and avoided cost prices.

Table B.2 – Woody Biomass Generation on PacifiCorp's System

St.	Name	City	Generation Method	Size (MW)
CA	Roseburg Forest Products	Weed	QF – Self supply first and sell excess	10.0
OR	Roseburg Forest Products *	Dillard	QF – Self supply first and sell excess	45.0
OR	Biomass One	Medford	QF	32.0
OR	Warm Springs	Warm Springs	Self-supply	9.0
OR	Douglas County Forest Products	Roseburg	QF – Self supply first and sell excess	6.3
OR	Rough & Ready Lumber	Cave Junction	QF	1.5
OR	Freres Lumber	Mill City	QF	10.0
WA	Georgia Pacific Corporation **	Camas	PacifiCorp Asset	52.0
	TOTAL			**166**

* Roseburg Forest Products (Dillard) – 20 MW is exported to PacifiCorp
** Georgia Pacific Corporation – currently operating at 14 MW

[7] There are six landfill gas plants with a total capacity of 14.6 MW, three each in Oregon and Utah which are not considered for this analysis.

Forest Thinnings

Forest thinnings represents a significant amount of fuel and electricity potential. However, it is inaccessible in the current market environment in the near or mid-term. The Energy Trust of Oregon and Oregon Forest Resources Institute suggest that up to 300 to 500 MW might be produced given available forest fuel, but is greatly dependent on workable and efficient supply and contracting mechanisms. Forest residue, if collected, represents the largest potential source of biomass energy in Oregon. Depending on the generation facility or facilities, the total electricity production could be 300 to 500 MW or more for approximately 10 years, if all of the residue could be collected and used. None of this potential is available in the near or mid-term. There is no infrastructure to gather forest residue, and costs to gather that material alone are estimated at $40–50/MWh, which is comparable to current wholesale market electricity prices. There are also significant administrative and regulatory barriers to gathering and using forest thinning. No generation projects exist today that use forest thinnings as their source of fuel to the plant. Current air regulations make it extremely difficult to permit such an operation, and contracts for supply, which must be made with the U.S. Forest Service, are limited at this time. These issues are beyond PacifiCorp's control at this point in time and therefore this market segment, while potentially promising in the long term, does not present near- or mid-term opportunities for PacifiCorp. Consequently, PacifiCorp is focusing on real project opportunities at a known customer's site and will continue to work with government agencies and/or private business to develop further incentives at the federal and state level to encourage the development of biomass generation.

Market Barriers

Low Electricity Prices

Current wholesale market electricity prices do not support the development of new biomass power plants. Even the current standard QF avoided cost prices do not support the development of a stand-alone QF project. Most of the standard QF projects under development are utilizing the available incentives and low-cost financing to incrementally construct the generation portion of a boiler up-grade or replacement project. In particular, the price of electricity is not sufficient to support the total cost of building and operating a plant including any fuel transportation costs. Low retail prices in the Pacific Northwest also limit the value of self-generation. Low wholesale prices limit the opportunities for selling electricity. There are a limited number of QF projects being developed at operating mills because natural gas costs have remained at a level whereby biomass fuel is not competitive.

High Installation Costs

The capital cost of developing biomass-based generation systems is high, especially in smaller-scale operations. The estimated capital cost of a greenfield biomass cogeneration plant is in excess of $3,500 per installed kilowatt. This is because the project consists of designing, siting, and constructing an entirely new power plant with all ancillary facilities and grid interconnection, not just installing new equipment at an existing site. Many forest products firms indicate that capital costs often contribute to unfavorable internal rates of return, and that this limits generation projects from moving forward. In other cases (in particular, wood burning plants) the inability to guarantee a long-term fuel supply has kept companies from obtaining financing.

Air Permitting Requirements

Obtaining required air quality approvals increases the project development costs and, in some cases, the operating costs of biomass projects. The smaller projects run by end-users are not familiar with air quality requirements and many cannot afford the cost of compliance.

Lack of Financial Recognition of Environmental Benefits

Although renewable energy credits (RECs) provide benefits to biomass-produced energy, the value of RECs in the market is low whether for compliance or the voluntary market. Many developers are unfamiliar with how to pursue the sale of RECs in the market. There are other benefits that are not accounted for as yet in the market such as greenhouse gas emission reduction. For the forest residue resources, an added benefit is reduced emissions from controlled combustion with emissions controls as compared to the open forest slash burn practice. However, these benefits have not been quantified. The biomass industry would benefit from policies and assistance that recognize that biomass offers superior benefit related to greenhouse gas emissions.

Cost of Fuel Transportation

The cost of collecting and transporting hard biomass fuels is expensive. This is especially true for forest residue. In addition, any regional plant that collects waste from nearby forest sites and delivers it to a central processing facility will face high transportation costs. The cost to ship the fuel 100 miles needs to be evaluated against transmission costs for the electricity. In general, for projects less than 5 MW, it is impractical to transmit electricity for long distances because the costs associated with the required transaction costs, wheeling charges, and line losses are not offset by the value received for the electricity. In the case of some larger projects, the economies of scale of developing a larger project can offset the cost of wheeling electricity from the site to the host utility. These larger projects, however, are limited in number. With a mature fuel market and transportation network in place, it is expected that mill waste would flow to the projects within the PacifiCorp service areas.

APPENDIX C – ENERGY ANALYSIS REPORT

ENERGY ANALYSIS REPORT

3/31/2014

2013 IRP Action Plan – Plant Efficiency Improvements

A multi-plant analysis of potential energy conservation opportunities at wholly owned PacifiCorp Energy generation facilities.

PACIFICORP ENERGY
A DIVISION OF PACIFICORP

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Executive Summary

Background

The 2013 IRP Action Plan calls for an assessment of the wholly owned PacifiCorp Energy generation facilities to determine possible areas for energy efficiency improvements. This assessment was to be done in light of the results of the studies completed for the Washington Initiative 937 (I-937). In response to this action item, PacifiCorp completed inspections at the following eight plants:

Dave Johnston Plant – Glenrock, Wyoming
Naughton Plant – Kemmerer, Wyoming
Huntington Plant – Huntington, Utah
Currant Creek Plant – Mona, Utah
Hunter Unit 3 – Castle Dale, Utah
Lakeside Plant – Lindon, Utah
Blundell Plant – Milford, Utah
Gadsby Plant – SLC, Utah

The purpose of this report is to outline the methods used to identify potential systems and equipment providing cost-effective energy efficiency improvements, summarize the outcomes of the inspections and rank the identified systems and equipment according to cost-effective analysis. The systems identified will be separated into three categories for each plant: (1) Having a high potential to be cost-effective, (2) needing further study to determine cost-effectiveness, or (3) as being unlikely to be cost-effective.

Methodology

Using the experience gained from energy efficiency studies for I-937 that were performed at Jim Bridger and Chehalis, systems and equipment at each plant were evaluated for potential to investigate. This was done by reviewing the operating characteristics of major plant systems using the plant distributive control system (DCS) information. Load dependent systems and equipment were evaluated at or near full plant capacity. The amount of wasted energy at full load is an indicator of the potential for cost-effective energy savings. Once the most likely candidates were identified, the systems and equipment were inspected to gather additional data and to discuss the operation with plant personnel. Systems not controlled through the plant DCS, typically load independent (lighting, compressed air, etc.), were also reviewed.

Summary of Results

The following systems and equipment were generally found to hold a high potential for cost-effective energy savings improvements:

- Compressed Air Controls and Dyer Upgrades/Controls – Huntington (~1,800MWh/yr), Hunter (~1,000MWh/yr)
- Heat Trace Thermostatic Control – Huntington (~80MWh/yr), Naughton (~100MWh/yr), Dave Johnston (~120MWh/yr)
- RO Water Treatment Systems – Naughton (~200MWh/yr), Dave Johnston (~190MWh/yr)
- Lighting Controls – All plants*

* Lighting retrofits to accomplish production efficiency gains do not meet the cost effective test due to the initial cost of preferred LED lighting technologies. Two opportunities for lighting efficiency improvements exist generally at each plant:

1. All plants can use new or upgraded controls for lighting to save energy. A common theme at each plant was that exterior lighting is on during daylight hours. The controls for these types of fixtures tend to malfunction or become inoperable quickly due to the harsh environment. These controls should be replaced and/or upgraded. Another commonality is that many outbuildings and unoccupied areas had lighting on at all times. Areas like this that use fluorescent lighting would benefit from occupancy sensors.
2. Emergency lighting is typically left on at all times. In some plants, emergency lighting consists almost entirely of incandescent lights. Upgrading these lights to CFL or LED and ensuring that they only turn on in loss of power has potential to be a cost-effective way to save energy.

The following systems show potential but require further study:

- ID Booster Fan – Huntington Unit 1
- Coal Conveyors – Huntington Plant
- Condensate Pumps – Hunter Unit 3, Naughton, Lakeside, and Currant Creek Plants
- Compressed Air System – Naughton Plant
- PA Fans – Hunter Unit 3, Dave Johnston Plant
- Boiler Water Feed Pumps – Dave Johnston Units 1 & 2
- Demineralization Water Pumps – Lakeside, Currant Creek Plants

Projects by Plant

Dave Johnston

The systems inspected during the site visit to Dave Johnston Power Plant include the following:

Boiler Feed Water Pumps	Compressed Air System
FD and ID Fans	Reverse Osmosis (RO) Water Treatment
PA Fans	Lighting
Condensate Pumps	

Potentially Cost-Effective Projects

Reverse Osmosis (RO) Water Treatment System: The RO system at Dave Johnston has a high potential for energy efficiency upgrades to be cost-effective. This system has new motors which are inverter duty rated. Also, there is space available to install VFD's. The control valves were mostly closed making the installation of VFD's worth considering. The projected savings would be approximately 125 MWh per year for stage one and approximately 75 MWh per year for stage two.

Heat Trace Controls: There are potential opportunities for efficiency improvements by fixing or upgrading the thermostatic controls on the heat trace runs around the plant.

Lighting Controls: There are opportunities for efficiency improvements through lighting control upgrades.

Systems Requiring More Research

Boiler Feedwater Pumps: The boiler feed water pumps for units 1 & 2 are electric driven pumps. At near full load the control valve was only 25% open for unit 1 and 33% open for unit 2. The cost of this project would be high due to the voltage of the pumps, the need to purchase new motors, the size of the motors being replaced (2500 hp), the cost of the VFD's for the voltage/size of the motors and the lack of space nearby. A detailed analysis of the energy savings as well as the costs of the project would need to be conducted to determine cost effectiveness. The Feedwater pumps for Units 3 & 4 do not have sufficient potential for cost-effective energy savings as they are configured differently than 1 & 2.

Primary Air (PA) Fans: The PA Fans for units 1 & 2 represent another potential opportunity. There are six 200 hp motors providing primary air for units 1 & 2. These are smaller motors which would bring costs down for replacement, however space for the VFD's would be a major factor. The fan dampers are about 50% closed or slightly more. The energy saved on this project may not be sufficient to offset the cost. The PA Fans for units 3 & 4 have two large motors each and run with less damping at full load. Due to the large size of the motors and the more efficient configuration, potential for cost-effective energy savings is very low.

Unlikely to be Cost-Effective

Compressed Air: The compressed air system at Dave Johnston Plant did not contain any cost-effective energy efficiency measures.

Forced Draft (FD) & Induced Draft (ID) Fans: The FD and ID fans were not damped enough to provide cost-effective energy efficiency measures.

Lighting Retrofit: The following table shows the cost-effective calculation for the lighting at Dave Johnston Plant. The cost and energy savings numbers are taken from the Evergreen study included in the appendix[8]. The columns under "Net" show the cost-effective ratio for the project based on the depreciation life. Any project with a ratio under 1 is not cost-effective.

2014 IRP Cost Effective Lighting Cost and Benefit Revenue Requirement Calculations											
				PV Rev Rqt Benefits		PV Rev Rqt (Costs)		**Net**			
	Project Cost in 2014 $s	MWh Savings	Decrement Cost Curve Used	Non_OR	OR	Non_OR	OR	**Non_OR**	**OR**	Non-OR Depreciable Life	OR Depreciable Life
Dave Johnston	$2,711,800	4,891	West Commercial Lighting	$1,402,949	$748,164	($2,805,147)	($2,642,350)	0.50	0.28	2027	2023

Naughton

The systems inspected during the site visit to the Naughton Power Plant include the following:

- Reverse Osmosis Water Treatment System
- Condensate Pumps
- Boiler Feed Water Pumps
- FD & ID Fans
- Reverse Osmosis Water Treatment System
- Booster Fan
- Cooling Tower
- Compressed Air
- Lighting

Potentially Cost-Effective Projects

Reverse Osmosis (RO) Water Treatment System: The RO system at Naughton has a high possibility for energy efficiency upgrades to be cost-effective. There are two separate RO systems, one acting as a backup for the other. The valves were only about 10% open. The motors are new 480 volt, inverter-duty rated motors. There is room nearby for VFD placement. The costs to implement the energy savings on this system should be relatively low. The projected savings would be approximately 190 MWh per year for each unit.

Heat Trace Controls: There are potential opportunities for efficiency improvements by fixing or upgrading the thermostatic controls on the heat trace runs around the plant.

Lighting Controls: There are opportunities for efficiency improvements through lighting control upgrades.

Systems Requiring More Research

Condensate Pumps: The costs of upgrading the condensate pumps will be high. However, there is enough potential in energy savings (a high-level estimate of 3,500 MWh per year) to justify further researching the costs to evaluate cost-effectiveness. The motors are large, 1000 – 1500 hp, at the medium voltage level and space will be an issue.

Compressed Air: There may be potential at Naughton to save energy on the compressed air system. The system requires more research because all the compressors were not running. The system needs to be operating in the normal condition in order to determine how much potential there is in the project.

Boiler Feed Water Pumps: The boiler feed water pumps for Naughton 1 & 2 are electric driven. The control valves are 77% open, which means the potential for energy savings is small. This system may still warrant more research before being discarded as a potential cost-effective energy efficiency project.

[8] Appendices to the Energy Analysis Report have been included on a CD with the 2013 IRP Update filing.

Unlikely to be Cost-Effective

Cooling Tower: The cooling towers for units 1 & 3 do not have VFD control. The operating procedure of the plant is to keep the water temperature as low as possible. The installation of VFD"s would not provide much in the way of saved energy.

Booster Fan: The booster fan damper was not closed enough to make project cost-effective. For a VFD, this project would require a new motor as well as long runs for the wire making project costs too high.

FD & ID Fans: The FD & ID fans were not damped enough to offset the potential costs of the upgrade. There were considerable space restrictions as well as the need for new motors along with the other costs of VFD installation.

Lighting Retrofit: The following table shows the cost-effective calculation for the lighting at Naughton Plant. The cost and energy savings numbers are taken from the Evergreen study included in the appendix. The columns under "Net" show the cost-effective ratio for the project based on the depreciation life. Any project with a ratio under 1 is not cost-effective.

2014 IRP Cost Effective Lighting Cost and Benefit Revenue Requirement Calculations

				PV Rev Rqt Benefits		PV Rev Rqt (Costs)		**Net**			
	Project Cost in 2014 $s	MWh Savings	Decrement Cost Curve Used	Non_OR	OR	Non_OR	OR	**Non_OR**	**OR**	Non-OR Depreciable Life	OR Depreciable Life
Naughton	$2,156,140	3,684	East Commercial Lighting	$1,333,762	$1,236,631	($2,269,660)	($2,249,629)	0.59	0.55	2029	2028

Huntington Plant

The systems inspected at Huntington Plant include the following:

- Raw Water Supply
- Coal Conveyor (Reddler Deck) Motors
- Heat Trace Controls
- Reverse Osmosis Water Treatment
- Compressor Controls
- ID Booster Fans
- Lighting

Potentially Cost-Effective Projects

Compressor Controls: The compressed air system at Huntington Plant is comprised of 4 new Cameron compressors. During the site inspection one of the compressors was running unloaded. Also, the dryers were not efficient and the dew points settings were aggressive. The proposed upgrades to this system include new dryer, upgraded controls for the dryers and a central control system for the compressors and dryers with only two compressors running at a time. Two of the existing dryers would not be needed and turned off. The potential energy savings with this configuration would be 1,800 MWh per year. The plant compressed air load requirements would need to be confirmed before implementing the proposed configuration.

Heat Trace Controls: There are potential opportunities for efficiency improvements by fixing or upgrading the thermostatic controls on the heat trace runs around the plant. The plant has a large amount of heat trace. The amount of heat trace not currently on thermostatic control needs to be identified and quantified. There appears to be potential to capture savings in this area.

Lighting Controls: There are opportunities for efficiency improvements through lighting control upgrades.

Systems Requiring Further Research

RO Water Treatment System: The RO system flow is controlled with a manual control valve. This system has potential for saving energy but more research is needed to determine cost-effectiveness. There wasn't as much throttling on the valve and therefore the benefit will be lower at Huntington than at other plants in the fleet.

ID Booster Fan: The Unit 1 booster fan is a system which is comprised of two 5,000 hp, 4160 volt fans. There was a significant amount of damping at full load. This project is on the border of being unlikely to be cost-effective but it does warrant a further look. Unit 2 was damped less at full load and will be considered after the cost-effective calculation for unit 1 is finished.

Unlikely to be Cost-Effective

Raw Water System: The raw water system was wasting energy. However, the potential costs of the upgrade would have been high due to the size and location of the pump motors. Also, upgrading the controls for the system would have a high cost.

Lighting Retrofit: The following table shows the cost-effective calculation for the lighting at Huntington Plant. The cost and energy savings numbers are taken from the Evergreen study included in the appendix. The columns under "Net" show the cost-effective ratio for the project based on the depreciation life. Any project with a ratio under 1 is not cost-effective.

2014 IRP Cost Effective Lighting Cost and Benefit Revenue Requirement Calculations											
				PV Rev Rqt Benefits		PV Rev Rqt (Costs)		**Net**			
	Project Cost in 2014 $s	MWh Savings	Decrement Cost Curve Used	Non_OR	OR	Non_OR	OR	**Non_OR**	**OR**	Non-OR Depreciable Life	OR Depreciable Life
Huntington	$2,355,760	3,855	East Commercial Lighting	$1,491,427	$1,491,427	($2,552,045)	($2,552,045)	0.58	0.58	2036	2030

Currant Creek Plant

The systems inspected during the visit to Currant Creek Plant include the following:

- Condensate Pumps
- Compressed Air
- Reverse Osmosis Water Treatment
- Water Storage Tank Recirculation Pumps
- Boiler Feed Pumps
- Lighting

Potentially Cost-Effective Projects

Lighting Controls: During the site visit there were unoccupied buildings and open areas that had lights on unnecessarily. These areas would benefit from motion sensor control of the lighting. Also, there were a number of exterior lights that were on during the day. These lights need to have the photo sensors fixed or replaced.

Systems Requiring Additional Research

Condensate Pumps: The condensate pumps at Currant Creek were wasting a high amount of energy across the control valve. The costs to upgrade this system will be high, though, so it requires additional study to determine cost-effectiveness. It has the potential to save roughly 2,000 MWh of energy per year if installed.

Compressed Air: The compressed air system was running efficiently. However, there did seem to be an opportunity to make improvements in the air drying controls. This system will need further scrutiny.

Unlikely to be Cost-Effective

RO Water Treatment: The RO system already had VFD's installed. This system was inspected due to the high potential for savings at the other plants. No opportunity available to save energy.

Water Storage Tank Recycle: At Currant Creek the pumps did not appear to be recycling as much as at Lakeside. Also, the valves were automatic and not manual. This allows for less waste than the manual valves.

Boiler Feed Pumps: This system did have a high amount of throttling that wastes energy. However, the piping system feeds a number of other loads besides the boiler. This means that the control valve would still need to be used reducing the amount of benefit derived from installing VFDs.

Hunter Unit 3

The Hunter plant is unique in the fact that only one unit is wholly owned by PacifiCorp. This removes general systems like the RO water treatment from the list of potential projects. It also complicates the compressed air system study. The systems inspected at Hunter Unit 3 include the following:

- Lighting
- Compressed Air
- PA Fans
- ID & FD Fans
- Cooling Towers
- Condensate Pumps

Potentially Cost-Effective Projects

Compressed Air: The compressors at Hunter were running inefficiently. As this project only pertains to Unit 3, only the compressor for that unit is considered. However, there is still potential for cost-effective energy saving opportunities for this as a stand-alone system.

Lighting Controls: There are opportunities for efficiency improvements through lighting control upgrades.

Systems Requiring Further Research

Condensate Pumps: There is a significant pressure drop across the control valve in the condensate piping system. However, project costs could prove to be prohibitive. One of the major impacts to cost would be finding room nearby to house the VFD's.

PA Fans: Up review of this system there appeared to be enough energy wasted to warrant a deeper look into actual project costs and savings.

Unlikely to be Cost-Effective

FD & ID Fans: The wasted energy does not appear to be great enough for this project to be cost-effective.

Cooling Tower Fans: The operating procedure of the plant is to keep the water temperature as low as possible. The installation of VFD"s would not provide much in the way of saved energy.

Lighting Retrofit: The following table shows the cost-effective calculation for the lighting for Hunter Unit 3. The cost and energy savings numbers are taken from the Evergreen study included in the appendix. The columns under "Net" show the cost-effective ratio for the project based on the depreciation life. Any project with a ratio under 1 is not cost-effective.

2014 IRP Cost Effective Lighting Cost and Benefit Revenue Requirement Calculations

				PV Rev Rqt Benefits		PV Rev Rqt (Costs)		**Net**			
	Project Cost in 2014 $s	MWh Savings	Decrement Cost Curve Used	Non_OR	OR	Non_OR	OR	**Non_OR**	**OR**	Non-OR Depreciable Life	OR Depreciable Life
Hunter U3	$1,820,276	2,308	East Commercial Lighting	$892,864	$835,464	($1,971,944)	($1,954,562)	0.45	0.43	2042	2029

Lakeside Plant

The systems inspected at Lakeside Plant include the following:

Condensate Pumps	Boiler Feed Water Pumps
Water Storage Tank Recirculation Pumps	Heat Trace
Lighting Controls	

Potentially Cost-Effective Projects

Lighting Controls: There is an opportunity to save energy with lighting controls. Ensuring buildings and other general spaces have occupancy sensors and photo-cells in working order would likely be a cost-effective measure.

Systems Requiring Further Research

Water Storage Tank Recirculation: The water storage tank recirculation pumps were running during the inspection. There was a manual control valve that was partially closed. Since this system didn't have inputs to the plant control system, we could not get good data on the amount of time that it was running and how often the valve was in that position. There is a possibility that this system could be improved to save energy in a cost-effective way. However, more data needs to be gathered.

Condensate Pumps: The condensate pumps discharge is heavily regulated at Lakeside Plant. There is also recirculation in the system that appears to be a source of wasted energy. This process configuration needs additional research to determine potential energy savings.

Heat Trace: The heat trace does not have thermostatic control in most cases. The circuits are turned on and off manually. More investigation is needed to determine the energy savings potential and cost.

Unlikely to be Cost-Effective

Boiler Feed Water Pumps: This system does not appear to have potential to be cost-effective.

Blundell Plant

Blundell is a geothermal power plant. The systems and processes used in this plant were unique enough to require a more thorough look to make sure potential savings weren't missed. Systems investigated during the Blundell site visit include the following:

Aux Cooling Water	Condensate Pumps	Unit 2 Feed Pumps
Blowdown Pumps	Compressed Air	Lighting Controls
Brine Transfer	Circulating Water Pumps	

Potentially Cost-Effective Projects

Lighting Controls: There is an opportunity to save energy with lighting controls. Ensuring buildings and other general spaces have occupancy sensors and photo-cells in working order would likely be a cost-effective measure.

Systems Requiring Further Research

Compressed Air: The dew point controls at many of our plants are set very aggressively. Making changes to the dew point controls to eliminate wasted energy is a very inexpensive way to conserve energy. The drying system at Blundell did not get reviewed, however, so this is one system that still needs to be reviewed.

Unlikely to be Cost-Effective

The remaining projects studied are unlikely to be cost-effective. The systems listed largely produce wasted energy related to recirculation. Projects in general with this type of wasted energy have not been found to have a positive pay-out.

Gadsby Plant

The Gadsby Plant consists of three gas steam units converted from coal and three gas “peaker” combustion turbine units. The three steam units are part of the old plant and would provide the most potential for energy savings projects. However, the steam units are intermittently run. They have a large amount of downtime. This makes the cost-effective test much harder to meet. The only potentially cost-effective project identified at this point would be lighting controls. This project will be investigated further.

APPENDIX D – ACCELERATED CLASS 2 DSM DECREMENT STUDY

This section presents the methodology and results of the energy efficiency, Accelerated Class 2 demand-side management (DSM) decrement study. The same methodology is used for this study as that presented in Volume II, Appendix N of the 2013 IRP, with one exception. For this analysis the amount of Class 2 DSM is re-optimized incorporating accelerated ramp rates that were inputs to Cases C-14, C-15 and C-18 in the 2013 IRP. This portfolio is used as the base portfolio to calculate the decrement value ("avoided cost") of various types of Class 2 DSM resources.

To align with the resource costs applied for resource portfolio development using the System Optimizer (SO) capacity expansion model, cost credits are applied to the Accelerated Class 2 DSM decrement 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.[9]

Modeling Approach

The modeling approach is the same as explained in Appendix N of the 2013 IRP report. For this sensitivity, the generation capacity investment deferral benefit is recalculated using the portfolio created with accelerated DSM assumptions. The avoided cost values are calculated for the same 17 Class 2 DSM measure shapes, each at 100 megawatts (MW) maximum capacity and available starting in 2013 and for the duration of the 20-year IRP study period. The production cost differences with and without each of the Class 2 DSM resources are derived using the Planning and Risk (PaR) model, which are then added to the capacity value calculated by the SO model and added to the cost credits as outlined above. The PaR decrement values are determined for one CO_2 tax scenario: medium (starting at $16/ton in 2022 and escalating to $26/ton by 2032).

Generation Resource Capacity Deferral Benefit Methodology

PacifiCorp used the SO model to determine the generation resource capacity deferral benefit. A single capacity benefit is calculated for an aggregate Class 2 DSM resource. This is accomplished by running SO with a resource portfolio that excludes 100 MW of zero cost Class 2 DSM resource (Change Case), and then comparing the fixed portfolio costs against the cost of the portfolio derived by the SO model that includes the Class 2 DSM program at zero cost (Base Case). The simulation period is 20 years. As a simplifying assumption, PacifiCorp applies the East "system" aggregate Class 2 DSM load shape for the generic DSM resource, because the next deferrable resource is located in the east side of PacifiCorp's system. The aggregate Class 2 DSM load shape 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

[9] Refer to Volume 1, page 147 of the 2013 IRP for a summary of the T&D investment deferral and stochastic risk reduction cost credits applied to the SO energy efficiency resource options.

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 the SO model production cost benefits are not taken into account to avoid double-counting the benefit extracted from stochastic PaR model results.

Since a 100 MW Class 2 DSM resource is not sufficiently large enough to defer a full-sized CCCT, the SO model is configured to allow fractional CCCT unit sizes for both the Base Case and the Change Case. This allows the Class 2 DSM resource to partially displace the CCCT. Deferral of CCCT capacity may start as early as 2017.[10] Note that Class 2 DSM resources 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 calculated as a present value) to yield a value in nominal levelized dollars per megawatt-hour ($/MWh).

This value, along with the T&D investment deferral credit and stochastic risk reduction credit, are added to the PaR model decrement values to yield the final adjusted values.

Class 2 DSM Decrement Value Results

Table D.1 reports the nominal levelized avoided costs by DSM resource for 2013 through 2032, along with a breakdown of the three cost credits (capacity deferral, T&D investment deferral, and stochastic risk reduction) for the Accelerated Class 2 DSM decrement study. Table D.2 reports the differences between Table D.1 and Table N.1 from Appendix N of the 2013 IRP, Volume II (Non-Accelerated DSM decrement study). Tables D.3 and D.4 report the nominal avoided cost by year in $/MWh.

[10] When modeling a CCCT as a fractional resource, the timing of that CCCT in the portfolio can change from the base portfolio developed using full-sized CCCT resource alternatives.

Table D.1 – Nominal Levelized Accelerated Class 2 DSM Avoided Costs (2013-2032)

			Cost Credit Components ($/MWh)					
Resource	**Location**	**Load Factor**	**Capacity Resource Deferral**	**T&D Investment Deferral**	**Stochastic Risk Reduction**	**Total Credits**	**Total Avoided Costs before Cost Credits ($/MWh)**	**Total Avoided Costs Including all Cost Credits ($/MWh)**
Residential Cooling	East	10%	13.33	64.61	2.10	80.03	63.43	**143.46**
Residential Lighting	East	48%	13.33	12.85	2.52	28.70	46.76	**75.46**
Residential Whole House	East	35%	13.33	17.71	2.40	33.44	48.57	**82.01**
Commercial Cooling	East	20%	13.33	31.95	2.44	47.71	55.88	**103.59**
Commercial Lighting	East	48%	13.33	12.76	2.74	28.83	49.96	**78.79**
Water Heating	East	57%	13.33	10.45	2.67	26.45	47.19	**73.64**
Plug Loads	East	59%	13.33	10.80	2.52	26.65	45.48	**72.13**
System Load Shape	East	70%	13.33	8.88	2.62	24.82	45.62	**70.44**
Residential Cooling	West	7%	13.33	90.98	1.39	105.69	57.98	**163.67**
Residential Heating	West	25%	13.33	26.17	2.27	41.76	43.75	**85.51**
Residential Lighting	West	48%	13.33	12.85	2.81	28.99	44.50	**73.48**
Commercial Cooling	West	16%	13.33	37.75	2.24	53.32	51.22	**104.54**
Residential Whole House	West	49%	13.33	12.93	2.81	29.06	44.49	**73.55**
Commercial Lighting	West	48%	13.33	12.76	2.72	28.81	46.49	**75.30**
Water Heating	West	56%	13.33	10.45	2.90	26.68	44.42	**71.11**
Plug Loads	West	59%	13.33	10.89	2.77	26.98	43.35	**70.33**
System Load Shape	West	71%	13.33	8.61	2.85	24.79	43.56	**68.35**

Table D.2 – Difference – Nominal Levelized Class 2 DSM Avoided Costs (2013-2032)
Accelerated DSM less Appendix N (Non-Accelerated DSM)

Resource	Location	Load Factor	Cost Credit Components ($/MWh) Capacity Resource Deferral	T&D Investment Deferral	Stochastic Risk Reduction	Total Credits	Total Avoided Costs before Cost Credits ($/MWh)	Total Avoided Costs Including all Cost Credits ($/MWh)
Residential Cooling	East	0%	(5.17)	0.00	0.00	(5.17)	2.49	**(2.67)**
Residential Lighting	East	0%	(5.17)	0.00	0.00	(5.17)	(0.23)	**(5.40)**
Residential Whole House	East	0%	(5.17)	0.00	0.00	(5.17)	(0.10)	**(5.26)**
Commercial Cooling	East	0%	(5.17)	0.00	0.00	(5.17)	0.81	**(4.35)**
Commercial Lighting	East	0%	(5.17)	0.00	0.00	(5.17)	(0.09)	**(5.26)**
Water Heating	East	0%	(5.17)	0.00	0.00	(5.17)	(0.38)	**(5.55)**
Plug Loads	East	0%	(5.17)	0.00	0.00	(5.17)	(0.18)	**(5.35)**
System Load Shape	East	0%	(5.17)	0.00	0.00	(5.17)	(0.14)	**(5.31)**
Residential Cooling	West	0%	(5.17)	0.00	0.00	(5.17)	7.00	**1.83**
Residential Heating	West	0%	(5.17)	0.00	0.00	(5.17)	1.81	**(3.35)**
Residential Lighting	West	0%	(5.17)	0.00	0.00	(5.17)	0.80	**(4.37)**
Commercial Cooling	West	0%	(5.17)	0.00	0.00	(5.17)	3.12	**(2.05)**
Residential Whole House	West	0%	(5.17)	0.00	0.00	(5.17)	0.83	**(4.34)**
Commercial Lighting	West	0%	(5.17)	0.00	0.00	(5.17)	0.80	**(4.37)**
Water Heating	West	0%	(5.17)	0.00	0.00	(5.17)	0.58	**(4.59)**
Plug Loads	West	0%	(5.17)	0.00	0.00	(5.17)	0.62	**(4.55)**
System Load Shape	West	0%	(5.17)	0.00	0.00	(5.17)	0.49	**(4.68)**

Table D.3 – Annual Nominal Accelerated Class 2 DSM Avoided Costs, 2013-2032

		Decrement Values (Nominal $/MWh)									
Decrement Name	Actual Load Factor	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
EAST											
Residential Cooling	10%	111.88	116.28	115.75	119.02	114.08	130.81	143.09	163.78	135.84	196.67
Residential Lighting	48%	55.29	56.22	57.71	61.27	58.97	65.25	69.54	77.24	73.51	96.43
Residential Whole House	35%	60.82	62.03	62.87	66.24	63.88	71.10	77.35	85.35	79.60	105.51
Commercial Cooling	20%	76.80	79.04	80.56	83.40	80.35	90.62	99.57	111.34	98.01	136.84
Commercial Lighting	48%	56.32	57.46	59.56	62.27	61.42	67.19	72.88	78.31	75.59	102.81
Water Heating	57%	52.93	53.98	56.03	58.70	57.29	62.93	68.10	73.15	71.27	94.35
Plug Loads	59%	52.30	53.29	54.83	58.40	56.13	61.94	66.20	72.89	70.51	92.67
System Load Shape	70%	50.53	51.55	53.66	56.04	54.79	60.39	64.77	70.24	69.06	89.36
WEST											
Residential Cooling	7%	138.66	140.03	136.43	143.90	133.26	156.66	165.39	196.96	154.48	210.72
Residential Heating	25%	66.62	68.35	67.40	71.96	66.71	78.45	80.43	92.00	82.03	109.88
Residential Lighting	48%	55.06	56.33	57.36	60.53	58.29	64.68	68.01	74.36	72.12	90.09
Commercial Cooling	16%	83.10	84.42	83.95	87.89	84.28	94.94	102.92	116.04	99.42	131.82
Residential Whole House	49%	55.21	56.75	57.53	60.36	57.90	64.67	68.02	74.37	71.91	90.10
Commercial Lighting	48%	55.97	57.48	58.75	61.80	60.39	66.26	69.72	75.90	73.52	91.90
Water Heating	56%	52.83	54.27	55.20	58.30	56.48	62.24	65.37	71.05	69.75	86.82
Plug Loads	59%	52.38	53.85	54.76	57.39	55.46	61.64	64.63	70.31	68.72	86.43
System Load Shape	71%	50.51	51.79	52.91	55.49	53.93	59.62	62.08	67.24	67.17	83.20

Table D.4 – Annual Nominal Accelerated Class 2 DSM Avoided Costs, 2013-2032 (continued)

	Decrement Values (Nominal $/MWh)									
Decrement Name	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EAST										
Residential Cooling	173.28	168.89	142.12	136.26	223.12	148.68	215.00	202.53	119.84	149.84
Residential Lighting	93.64	88.10	83.46	89.03	106.21	95.62	109.35	107.49	90.86	99.79
Residential Whole House	102.35	95.19	88.10	93.32	119.20	101.68	118.69	115.96	95.94	106.26
Commercial Cooling	131.44	120.84	111.88	112.86	156.60	120.50	156.43	150.83	106.60	119.98
Commercial Lighting	99.67	90.99	89.03	94.79	114.73	101.49	116.00	113.29	97.55	104.61
Water Heating	92.63	85.37	84.26	89.29	104.71	95.95	106.01	103.67	91.95	99.66
Plug Loads	89.42	83.31	81.86	86.06	101.69	93.84	101.93	101.56	89.78	98.01
System Load Shape	86.63	81.17	80.44	85.90	97.92	92.38	100.91	99.58	92.28	97.87
WEST										
Residential Cooling	194.79	183.73	154.79	149.74	233.87	154.83	238.15	244.97	106.86	156.73
Residential Heating	105.33	97.72	90.64	94.96	120.56	97.32	121.24	118.68	84.88	106.89
Residential Lighting	87.46	85.73	84.68	86.83	98.52	90.15	105.55	105.32	86.96	97.60
Commercial Cooling	123.33	121.11	109.91	109.30	145.13	111.71	157.81	157.73	94.91	114.76
Residential Whole House	87.94	85.63	84.59	87.86	99.70	89.97	105.58	104.67	86.44	97.64
Commercial Lighting	89.51	87.55	86.88	90.01	100.17	91.52	110.23	109.49	90.09	99.65
Water Heating	84.97	83.17	82.42	85.57	94.95	87.69	102.35	101.87	86.72	96.08
Plug Loads	84.14	82.29	81.37	84.69	94.59	87.15	101.76	100.29	83.69	95.11
System Load Shape	81.97	80.21	79.83	83.28	91.00	85.67	99.25	97.64	85.73	94.33

The total avoided costs from the Accelerated Class 2 DSM are less than those reported in the Non-Accelerated Class 2 DSM decrement study as presented in Appendix N of the 2013 IRP. The lower avoided cost values are attributed to a lower capacity resource deferral credit ($18.49/MWh for Non-Accelerated DSM, $13.33/MWh for Accelerated DSM). The capacity resource deferral value is determined based on the fixed cost, size and timing of the resources that are deferred in the Change Case due to removal of the 100 MW of Class 2 DSM at zero cost. In the Change Case for the Non-Accelerated Class 2 DSM analysis, the fractional CCCT is selected in 2020 and 2023, while in the Change Case of the current Accelerated Class 2 DSM decrement study, the first CCCT is selected in 2024 because more DSM resources are available due to accelerated ramp rates. As a result, the timing of the CCCTs that could be deferred by the 100 MW of zero cost Class 2 DSM is different in the two decrement studies. Table D.5 shows the differences in expansion resource portfolios between the Change Case and the Base Case of the Non-Accelerated DSM decrement study presented in Appendix N of the 2013 IRP.

Table D.5 – Portfolio Difference – Appendix N (Non-Accelerated DSM)

	Capacity (MW), Non-Accelerated Class 2 DSM																			
Resource	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Existing Plant Retirements/Conversions																				
Expansion Resources																				
CCCT J 1x1	-	-	-	-	-	-	-	96	-	-	8	395	(190)	(147)	(45)	-	(1)	-	-	-
FOT Mona Q3	-	-	-	-	23	93	94	15	16	14	8	(263)	(159)	(38)	-	(1)	-	1	1	1
Expansion Resources																				
FOT COB Q3	-	-	63	93	69	-	-	-	-	-	-	(51)	-	-	-	-	-	-	-	-
FOT MidColumbia Q3	(131)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FOT MidColumbia Q3 - 2	225	94	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Additions, Long Term Resources	-	-	-	-	-	-	-	96	-	-	8	395	(190)	(147)	(45)	-	(1)	-	-	-
Annual Additions, Short Term Resources	94	94	94	93	92	93	94	15	16	14	8	(314)	(159)	(38)	-	(1)	-	1	1	1
Total Annual Additions	94	94	94	93	92	93	94	111	16	14	16	81	(349)	(185)	(45)	(1)	(1)	1	1	1

For the Change Case in the Non-Accelerated DSM decrement study, prior to 2020 the only resources deferred are FOTs, which have no fixed costs, and provide no capacity deferral benefits. Capacity benefits materialize beginning 2020, with the partial displacement of a fractional CCCT resource. The incremental DSM from the Accelerated DSM case results in CCCTs being eliminated, reduced and delayed (starting with fractional CCCTs) beginning in 2020, as compared to the Non Accelerated DSM case, which results in reduced capacity benefits. Table D.6 shows the differences in expansion resource portfolios between the Change Case and the Base Case for the Accelerated DSM study. For this Change Case, the deferral resources in the front years continue to be FOTs, but the partial displacement of CCCTs starts later, in 2024.

Table D.6 – Portfolio Difference – Non-Accelerated DSM

		Capacity (MW), Accelerated Class 2 DSM																			
	Resource	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
East	**Existing Plant Retirements/Conversions**																				
	Expansion Resources																				
	CCCT J 1x1	-	-	-	-	-	-	-	-	-	-	-	423	(109)	(176)	(23)	(1)	-	-	-	-
	FOT Mona Q3	-	-	-	-	-	-	58	94	-	93	93	(171)	(163)	(19)	-	-	-	1	1	1
West	**Expansion Resources**																				
	FOT COB Q3	89	94	94	93	93	22	-	-	69	-	-	(81)	-	-	-	-	-	-	-	-
	FOT MidColumbia Q3 - 2	5	-	-	-	-	70	36	-	25	-	-	-	-	-	-	-	-	-	-	-
	Existing Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Annual Additions, Long Term Resources	-	-	-	-	-	-	-	0	-	-	-	423	(109)	(176)	(23)	(1)	-	-	-	-
	Annual Additions, Short Term Resources	94	94	94	93	93	92	94	94	94	93	93	(252)	(163)	(19)	-	-	-	1	1	1
	Total Annual Additions	94	94	94	93	93	92	94	94	94	93	93	171	(272)	(195)	(23)	(1)	-	1	1	1

Overall, the delay in timing of the deferred CCCT reduces the net present value of savings in fixed costs, which lowers capacity deferral credits from $18.49/MWh in Appendix N to $13.33/MWh in the Accelerated DSM study.

Consistent with the results for the 2013 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.

APPENDIX E – IRP TABLE A.7 CORRECTION

The following table was included as part of PacifiCorp's response to Wyoming Public Service Commission Staff Data Request 2.5 (Docket No. 20000-424-EA-13). This is the corrected version of Table A.7 from the 2013 IRP.

Table E.1 – Jurisdictional Contribution to Coincident Peak 1997 through 2012

Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	System
1997	174	415	2,799	2,490	843	1,049	7,770
1998	190	440	2,900	2,968	810	1,046	8,354
1999	214	697	2,208	3,170	791	892	7,972
2000	154	523	2,347	3,721	756	979	8,480
2001	124	421	2,122	3,514	627	1,091	7,899
2002	162	689	2,139	3,758	758	1,043	8,549
2003	155	573	2,360	4,038	774	1,022	8,922
2004	120	603	2,202	3,869	740	1,094	8,628
2005	171	681	2,240	4,056	708	1,081	8,937
2006	156	561	2,684	4,011	816	1,094	9,322
2007	160	701	2,606	4,424	754	1,129	9,775
2008	171	682	2,522	4,189	728	1,208	9,501
2009	153	517	2,574	4,394	795	987	9,420
2010	144	527	2,444	4,338	757	1,208	9,418
2011	143	549	2,189	4,638	707	1,204	9,431
2012	156	782	2,163	4,756	749	1,225	9,831
Average Annual Growth Rate							
1997-2012	-0.73%	4.32%	-1.70%	4.41%	-0.79%	1.04%	1.58%

*Coincident peak's do not include sales for resale or SE Idaho exchange

CONFIDENTIAL APPENDIX F – BREAKEVEN ANALYSIS

Introduction

On November 25, 2013 the Washington Utilities and Transportation Commission (WUTC) acknowledged PacifiCorp's 2013 IRP. In Docket UE-120416 the WUTC stated the 2013 IRP "meets the requirements of Revised Code of Washington 19.280.030 and Washington Administrative Code 480-100-238."

The WUTC further provided "suggestions and requests for future IRP filings", which included a request to update PacifiCorp's coal analysis as part of the 2013 IRP Update and include various price curves for carbon regulation and price curves for natural gas where it would be more economical to operate a given unit using natural gas as opposed to coal. This Confidential Appendix is included in the 2013 IRP Update to satisfy the WUTC requested update.

Carbon Regulation

In their memo the WUTC specifically mentioned two carbon related items: (1) The September 20, 2013 EPA proposed regulations on new coal and natural gas-fired generating plants, and (2) the June 25, 2013 Presidential Memorandum directing the Environmental Protection Agency (EPA) to propose regulations on existing coal plants by June 2014.

PacifiCorp recognizes there is uncertainty around the potential costs resulting from pending regulation of CO_2 emissions applicable to existing natural gas and coal resources. Additionally, despite issuance of the June 2013 Presidential Memorandum, there is tremendous uncertainty about the regulatory mechanisms that might be used in EPA's pending rule-making process, and consequently there continues to be uncertainty in the cost for future regulations on CO_2 emissions from existing sources. This uncertainty is the reason that PacifiCorp evaluated a range of CO_2 price scenarios in the 2013 IRP and in the financial analyses included within Confidential Volume III.

PacifiCorp has reviewed the June 2013 Presidential Memorandum in which President Obama directed the EPA to complete greenhouse gas (GHG) standards for both new and existing power plants. For existing sources, EPA was directed to issue "standards, regulations, or guidelines, as appropriate" that address GHG emissions from modified, reconstructed, and existing power plants.[11] The Presidential Memorandum did not explicitly set forth regulations for existing coal plants. The proposed standards, regulations, or guidelines are to be issued by June 1, 2014, finalized by June 1, 2015, with implementation of regulations as proposed in SIPs required by June 30, 2016. EPA would then review the implementation plan proposed by each state. Accordingly, even if EPA follows the President's aggressive schedule, the effective compliance dates for these standards, regulations, or guidelines are a number of years into the future.

[11] Presidential Memorandum – Power Sector Carbon Pollution Standards, June 25, 2013.

The June 2013 Presidential Memorandum did not detail how EPA will approach CO_2 regulation or what the resulting standards, regulations, or guidelines will ultimately entail for existing resources.

Absent any information on how EPA intends to proceed with its rule-making process, and without any information on how individual states will propose to implement those regulations through a SIP, there is currently no means to develop a specific CO_2 price assumption that accurately reflect potential CO_2 regulation.[12] As such the CO_2 assumptions used in the 2013 IRP remain reasonable.

The IRP assumptions already represent 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. The range of assumptions are based upon independent third- party price projections, with a high scenario that is consistent with prominent legislative proposals, and with even higher scenarios developed consistent with stakeholder input during the pre-filing public input process for this IRP. This approach was taken because, as of today, there are a wide range of potential future policy tools that may be employed to regulate CO_2 emissions. Because the June 2013 Presidential Memorandum does not direct a particular type of regulatory approach, it does not make one particular approach more or less likely and therefore does not change the IRP assumptions. Similarly, because there is no detail on which to base an analysis, it does not make a particular CO_2 price forecast used in the IRP more or less reasonable.

Given the timeline set forth in the Presidential Memorandum, the Company will have multiple opportunities to re-evaluate its CO_2 price assumptions incorporating new information with issuance of proposed regulations in June 2014. As assumptions are developed for the 2015 IRP, the Company will re-evaluate current market conditions and policy developments along with current forecasts from external sources in establishing updates, if any, to its CO_2 price assumptions. At this point however there is no reason to believe the assumptions contained in the 2013 IRP are not reasonable.

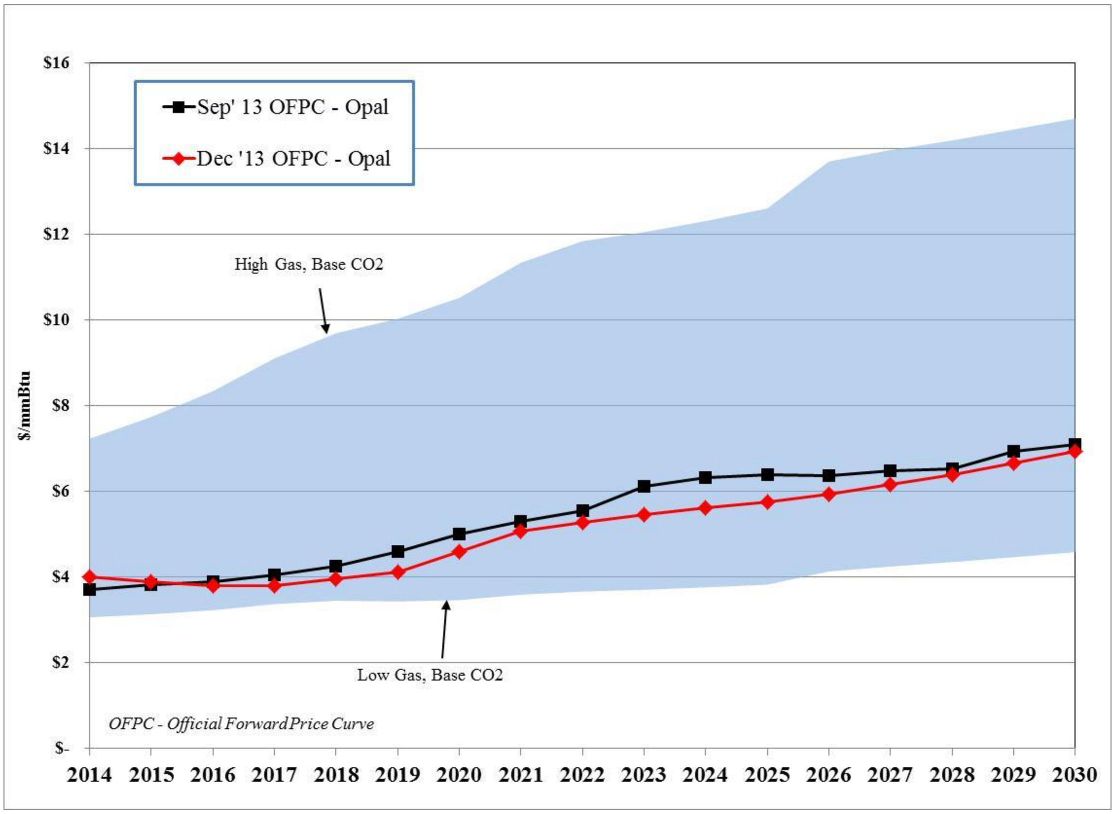
Natural Gas Prices

The WUTC also pointed to changes in gas prices, and suggested that "…a more detailed analysis that focuses on the gaps between various projections that the Company used and identifies the price level at which it would become cost effective to switch an existing coal plant to natural gas is required to better inform the Company's decision making process".[13] Again, the Company posits that the analysis already provided in Confidential Volume III is sufficient to find breakeven points.

Figure F.1 below includes a shaded area representing the spread between the high and low gas forecasts used in the 2013 IRP. The two lines on the graph are the September and December 2013 forecasts used in the IRP Update. As shown, the current forecasts are within the range analyzed for the 2013 IRP. As such, analysis contained within the IRP is applicable to find the breakeven points as requested.

[12] While some groups have made recommendations to EPA, EPA has provided no indication of how it plans to proceed through its rulemaking process.
[13] PacifiCorp IRP Acknowledgment Letter – Attachment, Washington Utilities and Transportation Commission, Docket UE-120416 at page 3.

Figure F.1 – Natural Gas Price Forecast for 2013 IRP Update



Confidential Volume III Analysis

As discussed above, PacifiCorp analyzed investment decisions contained in Confidential Volume III of the 2013 IRP across a wide range of gas and CO_2 price assumptions. There is not any additional information to suggest the range tested for the two variables is applicable today as it was then. Given that, results from PacifiCorp's analysis for Hunter Unit 1, Bridger Units 3 and 4 and Naughton Unit 3 shown in Confidential Volume III can be used to address the requests from the WUTC. That is, the analysis can be used to estimate valid breakeven points as requested.

Emission Control PVRR(d) Analysis

Methodology

As discussed in the 2013 IRP, present value revenue requirement differential (PVRR(d)) analyses are used to quantify the benefit or cost of completing coal unit environmental investments by legally binding compliance deadlines as compared to the next best alternative. The PVRR(d) for any given environmental investment is calculated as the difference in system costs between two System Optimizer simulations. In one System Optimizer simulation, the costs for near-term and prospective future environmental investments required for a unit to continue operating as a coal-fueled facility are included as incremental system costs. In a second System Optimizer simulation, it is assumed that coal-fueled operations cease at the compliance deadline, allowing the model to choose the next best compliance alternative where incremental environmental investment are avoided. In this second simulation, the System Optimizer model evaluates converting a unit to operate as a gas-fueled facility and early retirement as potential alternatives to the installation of emissions control equipment.[14] The second System Optimizer simulation also considers how cost and performance assumptions are affected when one or more units at a plant convert to natural gas or retire early.

The PVRR(d) analyses for the resources in questions (Hunter Unit 1, Jim Bridger Units 3 and 4, and Naughton Unit 3) were performed on broad range of different market scenarios pairing varying levels of natural gas prices and CO_2 costs. These scenarios looked at high, base, and low gas prices as well as high, low, and base CO_2 costs. One can interpolate breakeven points for both gas and CO_2 costs using these study results, as shown below.

To find the breakeven point for a single factor, the other factors must be held constant. That is, to isolate the effects of CO_2 prices for instance, the natural gas price relationship with PVRR(d) results is shown for the natural gas price scenarios in which the base case CO_2 price assumption is used. Holding CO_2 costs fixed at the base case assumption allows for finding an estimate for the breakeven natural gas price. Likewise, the CO_2 breakeven points are found using scenarios with base gas price forecasts.

Hunter Unit 1

The Hunter Unit 1 baghouse and low NO_X burner (LNB) breakeven analysis relies on an PVRR(d) analysis completed to support the appropriations request (APR), which was approved in May 2012, and summarized in Confidential Volume III of the 2013 IRP. Table F.1 shows the PVRR(d) results among five different scenarios analyzed in support of the APR which can be used to find the breakeven points for gas and CO_2 prices, as discussed above.

Confidential Table F.1 – Hunter 1 APR Emission Control PVRR(d) Analysis Results, 2026 SCR

Gas Price Scenario	Levelized gas price ($/MMBTU)	CO_2 Price Scenario	Levelized CO2 costs ($/ton)	PVRR(d) (Benefit)/Cost of Baghouse & LNB Investments ($m)
Base (December 2011)	$6.00	Base (December 2011)	$9.57	[redacted]
High with Base CO_2	$8.61	Base (December 2011)	$9.57	
Low with Base CO_2	$4.46	Base (December 2011)	$9.57	
Base with High CO_2	$6.00	High	$35.09	
Base with Zero CO_2	$6.00	Zero	0	

Figure F.2 graphically displays the relationship between the nominal levelized natural gas price at the Opal market hub over the period 2015 through 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Hunter Units 1 with the additional baghouse and SCR. To isolate the effects of CO_2 prices, the natural gas price relationship with PVRR(d) results is shown for the natural gas price scenarios in which the base case CO_2 price assumption is used. The result is a predicted breakeven value of [redacted] per MMBtu before gas conversion would be considered.

[14] In the case of an early retirement alternative, the System Optimizer model can fill the resource need by selecting from the full suite of supply side resources used in the IRP portfolio development process. Current new resource options are summarized in Volume 1, Chapter 6 of the 2013 IRP.

Confidential Figure F.2 – Relationship between Gas Prices and the PVRR(d) (Benefit)/Cost of the Baghouse and LNB Investments at Hunter Unit 1

Redacted

The results of a similar analysis for the breakeven value for CO_2 are shown in Figure F.3. Here, it is the relationship between the nominal levelized CO_2 cost over the 2015 to 2030 period and the PVRR(d) of continued coal operation of Hunter Units 1 with the additional baghouse and LNB that is shown. In this case, to isolate the effects of gas price changes, base case natural gas prices assumptions are maintained. As shown, CO_2 cost would have to be at a levelized value of [redacted] per ton or greater to consider gas conversion for this unit.

Confidential Figure F.3 – Relationship between CO_2 Prices and the PVRR(d) (Benefit)/Cost of the SCR Investments at Hunter Unit 1

Redacted

Jim Bridger 3 and 4

Breakeven analysis for Jim Bridger Units 3 and 4 can be completed relying on the analysis provided to support two regulatory filings: (1) Application for a Certificate of Public Convenience and Necessity (CPCN) filed with the Wyoming Public Service Commission on August 7, 2012[15], and (2) Voluntary Request for Approval of Resource Decision filed with the Public Service Commission of Utah on August 24, 2012[16]. The Company used the same analysis to support the Wyoming and Utah filings, and the base case natural gas, power, and CO_2 price assumptions are the same as the medium price assumptions used in the 2013 IRP.

Table F.2 shows the PVRR(d) results for five of the nine different scenarios analyzed in support of the Jim Bridger Unit 3 and Unit 4 CPCN analysis (and provided in Confidential Volume III of the 2013 IRP). These five represent the cases for the base gas, or CO_2 price scenarios.

[15] See Wyoming Docket No. 20000-418-EA-12. The Wyoming Public Service Commission approved the Company's CPCN application in a public deliberation on April 10, 2013.
[16] See Utah Docket No. 12-035-92.

Confidential Table F.2 – Bridger 3 and 4 CPCN Emission Control PVRR(d) Analysis Results

Gas Price Scenario	Levelized Gas Price ($/MMBTU)	CO_2 Price Scenario	Levelized CO2 costs ($/ton)	PVRR(d) (Benefit)/Cost of SCR Investments ($m)
Base (September 2012)	$5.72	Base (September 2012)	$ 9.05	[redacted]
High with Base CO_2	$7.65	Base (September 2012)	$ 9.05	[redacted]
Low with Base CO_2	$3.70	Base (September 2012)	$9.05	[redacted]
Base with High CO_2	$5.72	High	$24.20	[redacted]
Base with Zero CO_2	$5.72	Zero	$ -	[redacted]

These points can be used to perform analysis similar to that shown above for Hunter Unit 1. Figure F.4 shows the relationship between gas prices and the PVRR(d) of benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. Again, to isolate the impact of changes in gas prices, the CO_2 value was held constant at the base level. As shown in the figure, a breakeven price of [redacted] per MMBtu would be needed to consider gas conversion.

Confidential Figure F.4 – Relationship between Gas Prices and the PVRR(d) (Benefit)/Cost of the SCR Investments at Jim Bridger Units 3 & 4

Redacted

Figure F.5 below shows the relationship between CO_2 prices and the PVRR(d) of benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. Here the gas prices were held constant at the base level assumed. As shown, the breakeven levelized CO_2 price is [redacted]/ton.

Confidential Figure F.5 – Relationship between CO_2 Prices and the PVRR(d) (Benefit)/Cost of the SCR Investments at Jim Bridger Units 3 & 4

Redacted

Naughton Unit 3

PacifiCorp completed an Emission Control PVRR(d) analysis in its evaluation of SCR and baghouse investments required by December 31, 2014 to meet Regional Haze regulations at Naughton Unit 3. The analysis was completed in support of the Company's Application for a Certificate of Public Convenience and Necessity (CPCN) filed with the Wyoming Public Service Commission on September 16, 2011[17]. Information from this filing is used for the breakeven analysis requested. Table F.3 shows the PVRR(d) results for five different scenarios analyzed in support of the Naughton Unit 3 CPCN analysis. These are the scenarios relying on base assumptions for gas, or CO_2 prices.

Confidential Table F.3 – Naughton 3 CPCN Emission Control PVRR(d) Analysis Results

Gas Price Scenario	Levelized Gas Price ($/MMBTU)	CO_2 Price Scenario	Levelized CO2 costs ($/ton)	PVRR(d) (Benefit)/Cost of SCR and baghouse Investments ($m)
Base (December 2011)	$6.00	Base (December 2011)	$16.00	[redacted]
High with Base CO_2	$8.61	Base (December 2011)	$16.00	
Low with Base CO_2	$4.46	Base (December 2011)	$16.00	
Base with High CO_2	$8.61	High	$34.00	
Base with Zero CO_2	$6.00	Zero	$0	

[17] Wyoming Docket No. 20000-400-EA-11

Figure F.6 below shows a very strong linear relationship between the nominal levelized price of Opal natural gas prices and the PVRR(d) benefit/cost of the incremental environmental investments required at Naughton Unit 3. Based upon this trend, levelized natural gas prices would need to increase from $6.00 per mmBtu as was in the base case forward price curve to [redacted] per mmBtu to achieve a breakeven PVRR(d).

Confidential Figure F.6 – Relationship between Gas Prices and the PVRR(d) (Benefit)/Cost of the SCR and Baghouse Investments at Naughton Unit 3

Redacted

Higher CO_2 price assumptions improve the PVRR(d) in favor of the gas conversion alternative, and lower CO_2 prices erode the benefits of the gas conversion alternative; however, PVRR(d) results remain favorable to the gas conversion alternative when CO_2 prices are zero and paired with the base case natural gas price assumptions, as shown in Figure F.7. As with the trend described in the relationship between natural gas prices and the PVRR(d) results, the relationship between CO_2 prices and the PVRR(d) benefit/cost of the incremental environmental investments at Naughton Unit 3 is intuitive. Because the CO_2 content of coal is nearly double the CO_2 content of natural gas, higher CO_2 prices lowers the cost of emissions for the gas conversion alternative and lowers the fuel cost of other natural gas-fueled system resources used to offset any generation lost from the coal-fueled Naughton Unit 3 asset.

Confidential Figure F.7 – Relationship between CO_2 Prices and the PVRR(d) (Benefit)/Cost of the SCR and Baghouse Investments at Naughton Unit 3

Redacted