PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

September 21, 2011

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

RE: LC 52 – PacifiCorp's Response to Comments and Supplemental Coal Replacement Study

Pursuant to the administrative law judge's ruling on September 12, 2011 modifying the schedule, PacifiCorp d/b/a Pacific Power ("Company") encloses for filing its Response to the Oregon Party Comments on PacifiCorp's 2011 Integrated Resource Plan. Additionally, the Company is filing a Confidential Supplemental Coal Replacement Study. The confidential version is provided subject to Protective Order No. 11-186 adopted for the proceeding. A redacted version is also provided.

It is respectfully requested that all data requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

As indicated on the attached service list, a copy of this filing is being served to all parties on the service list. The confidential material is being provided only to persons on the service list who have executed the protective order.

Please contact Joelle Steward, Regulatory Manager, at (503) 813-5542, for questions on this matter.

Sincerely,

Andrea L. Kelly /JS

Andrea L. Kelly
Vice President, Regulation

Enclosure

cc: Service List – LC 52

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, on the date indicated below by email and/or US Mail, addressed to said parties at his or her last-known address(es) indicated below.

Vijay A. Satyal (W) (C)
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
vijay.a.satyal@state.or.us

Rebecca Sherman (W) (C)
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
rebecca.sherman@state.or.us

Gordon Feighner (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway – Ste 308
Portland, OR 97205
gordon@oregoncub.org

Robert Jenks (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway – Ste 308
Portland, OR 97205
bob@oregoncub.org

G. Catriona McCracken (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway – Ste 308
Portland, OR 97205
catriona@oregoncub.org

Jess Kincaid (W)
Community Action Partnership of Oregon
P.O. Box 7964
Salem, OR 97301
jess@caporegon.org

Irion A. Sanger (W) (C)
Davison Van Cleve
333 SW Taylor, Suite 400
Portland, OR 97204
mail@dvclaw.com

Janet L. Prewitt (W) (C)
Assistant Attorney General
Department of Justice
1162 Court St. NE
Salem, OR 97301-4096
Janet.prewitt@doj.state.or.us

John W. Stephens (W) (C)
Esler, Stephens & Buckley
888 SW Fifth Ave, Suite 700
Portland, OR 97204-2021
stephens@eslerstephens.com

Wendy Gerlitz (W) (C)
NW Energy Coalition
1205 SE Flavel
Portland, OR 97202
wendy@nwenergy.org

Fred Heutte (W) (C)
NW Energy Coalition
P.O. Box 40308
Portland, OR 97240-0308
fred@nwenergy.org

Mary Wiencke (W)
Pacific Power
825 NE Multnomah, Suite 1800
Portland, OR 97232
Mary.wiencke@pacificorp.com

Pete Warnken (W)
PacifiCorp Energy
825 NE Multnomah, Suite 600
Portland, OR 97232
Pete.warnken@pacificorp.com

Oregon Dockets (W)
Pacific Power
825 NE Multnomah, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Randy Dahlgren (W)
Portland General Electric
121 SW Salmon St. 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

Brian Kuehne (W)
Portland General Electric
121 SW Salmon St. 3WTC BR06
Portland, OR 97204
Brian.kuehne@pgn.com

V. Denise Saunders (W)
Portland General Electric
121 SW Salmon St. 1WTC1711
Portland, OR 97204
Denise.saunders@pgn.com

Erik Colville (W) (C)
Oregon Public Utility Commission
P.O. Box 2148
Salem, OR 97308-2148
Erik.colville@state.or.us

Jason W. Jones (W) (C)
Assistant Attorney General
Department of Justice
1162 Court St. NE
Salem, OR 97301-4096
Jason.w.jones@state.or.us

Donald W. Schoenbeck (W) (C)
Regulatory & Cogeneration Services Inc.
900 Washington St., Suite 780
Vancouver, WA 98660-3455
dws@r-c-s-inc.com

Megan Walseth Decker (W) (C)
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
megan@rnp.org

Jimmy Lindsay (W) (C)
Renewable Northwest Project
917 SW Oak, Suite 303
Portland, OR 97205
jimmy@rnp.org

Jeff Speir (W)
Sierra Club
85 Second St., 2nd Floor
San Francisco, CA 94105
Jeff.speir@sierraclub.org

Gloria D. Smith (W) (C)
Sierra Club Law Program
85 Second St., 2nd Floor
San Francisco, CA 94105
Gloria.smith@sierraclub.org

Jeremy Fisher (W)
Synapse Energy
485 Massachusetts Ave., Suite 2
Cambridge MA 02139
jfisher@synapse-energy.com

Dated: September 21, 2011

Ariel Son
Coordinator, Regulatory Operations

Response to the Oregon Party Comments on PacifiCorp's 2011 Integrated Resource Plan

Docket LC 52

1. INTRODUCTION

PacifiCorp filed its 2011 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on March 31, 2011. The Company's IRP was prepared in accordance with the terms of Order No. 10-066, in which Commission acknowledged the Company's 2008 IRP, as well as Order Nos. 07-002 and 07-047, in which Commission adopted the IRP Guidelines. The 2011 IRP was filed following an extensive public process that was outlined on page 22 of the IRP. In addition to the public process prior to the filing, the Company arranged a tutorial for interested parties for the models used for the IRP with the Company's model vendor Ventyx, held a workshop with interested parties on August 9, 2011, and provided a presentation to the Commission on August 19, 2011. The Company has also responded to nearly 270 data requests from parties to date.

As part of the IRP acknowledgment schedule adopted by the administrative law judge for this proceeding, parties filed comments and acknowledgment recommendations on August 26, 2011. Seven parties submitted written comments: Commission staff (Staff), Citizens' Utility Board (CUB), the Northwest Energy Coalition (NWEC), the Renewable Northwest Project (RNP), Oregon Department of Energy (ODOE), Industrial Customers of Northwest Utilities (ICNU), and Sierra Club. In response to these comments, PacifiCorp submits these reply comments for consideration. These comments are organized by topic, covering coal plant investment analysis, demand-side management resources, renewable resource acquisition strategy and costs, capacity planning reserve margin, and renewable portfolio standard (RPS) compliance.

2. EXECUTIVE SUMMARY AND RECOMMENDATIONS

Comments from parties primarily focus on the following issues: coal plant investment analysis, demand-side management (DSM) resources, renewable resource acquisition strategy and costs, the capacity planning reserve margin, and renewable portfolio standard (RPS) compliance.

The parties raise concerns with respect to perceived shortcomings in modeling assumptions that bias the outcome of resource selection, particularly with respect to identification and analysis of environmental compliance costs. In these comments, the Company provides clarification to support its portfolio modeling assumptions and resource strategy conclusions. We note that with a few exceptions, the parties do not explain how their claimed IRP shortcomings tie to meeting specific Commission IRP Guidelines. Providing such context would be helpful in responding to comments in the future.

With respect to environmental compliance costs, the Company provides a Confidential Supplemental Coal Replacement Study ("Coal Replacement Study") filed along with these reply comments, which updates and expands upon the original coal utilization study conducted for the IRP. This supplemental analysis further demonstrates compliance with the IRP Guidelines.

With the responses and clarifications contained in this filing, along with the Coal Replacement Study submitted in conjunction with these comments, PacifiCorp believes that the requirements of the IRP Guidelines and Order No. 10-066 have been met and that the Company's 2011 IRP should be acknowledged.

3. REPLY COMMENTS

Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

Staff and other parties criticize the Company for not including a comprehensive assessment of coal unit investment costs in the IRP. The key themes and remarks from parties are as follows:

- Staff states that PacifiCorp failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations and therefore did not comply with the Commission's IRP Guidelines, specifically 1(c) and 4(g).[1]
- CUB states that the IRP is not complete because it does not include an analysis of the Company's underlying coal investments.
- Sierra Club requests that the Commission require the Company to develop unit-by-unit Continued Use and Operation (CUO) studies in the IRP. Sierra Club states that the CUO studies should: (1) test the economic merit of continued use with environmental retrofits against the retirement and optimized portfolio replacement; (2) evaluate the risk of retirement under difference cost scenarios, and; (3) allow feasible replacements as of the first year of the IRP analysis, or the earliest substantive environmental compliance deadline.
- Both CUB and Sierra Club point to Portland General Electric's (PGE) Boardman power plant operations analysis as an example of the type of analysis that PacifiCorp should have provided in its IRP.

As fully described below, the Company believes that the IRP, as supplemented by the new Coal Replacement Study, addresses the parties' concerns and meets the requirements of the Commission's IRP guidelines.

<u>Compliance with IRP Guidelines 1(c) and 4(g)</u>
Concerning Staff's belief that PacifiCorp has not met the IRP guidelines, the Company emphasizes that the IRP coal utilization study, documented on pages 180-182 and 236-240, incorporated the Company's emissions control project costs, including mercury MACT compliance costs, reasonably ascertainable at the time that the IRP model data was undergoing development. PacifiCorp believes that the IRP thus complies with Guideline 4(g) in this respect. Further, the Coal Replacement Study incorporates scenarios consisting of alternative carbon dioxide (CO_2) and natural gas prices, in full compliance with Guideline 4(g)'s requirement to identify alternative scenarios.

---

[1] Guideline 1(c): "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."
Guideline 4(g): "Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered."

As mentioned above, PacifiCorp believes that the attached Coal Replacement Study further addresses the concerns raised by the parties. The Company developed this study to support the Company's Wyoming application for a Certificate of Public Convenience and Necessity (CPCN) for Naughton 3 pollution control investments. The Coal Replacement Study uses the System Optimizer capacity expansion model to (1) test the economic merit of continued use with environmental retrofits against retirement and optimized portfolio replacement, (2) evaluate the risk of retirement under different cost scenarios, and (3) allow feasible replacements as of the earliest substantive environmental compliance deadline.

To support compliance with Guideline 1(c), this supplemental analysis reaffirms the findings of the coal utilization sensitivities performed for the IRP, and shows that the Company's coal resources, with planned incremental investments, will continue to provide reliable and least-cost electric service to customers in alignment with the IRP preferred portfolio and action plan.

Analysis of Emerging Environmental Regulations

In response to the parties' criticism that the Company did not sufficiently address emerging environment regulations, the Company summarize below the issues associated with the timing and uncertainty of the United States Environmental Protection Agency's (EPA) emerging emission control rules, the complexity of addressing the impact of emerging rules on coal plant operations on a system-wide basis, and how this complexity comes into play for the IRP.

At the time of decision-making for the complex multi-year projects that have recently been placed in service or will be placed in service in the near term, information pertaining to the currently emerging environmental regulations was simply not available, as the rulemaking processes had not begun.

Development of PacifiCorp's emissions control plan was primarily driven by EPA Regional Haze Rules and associated requirements. The Regional Haze program began with the Grand Canyon Visibility Transport Commission (Transport Commission), which was formed under the requirements of the 1990 Clean Air Act Amendments. The Transport Commission focused its efforts on the reduction of SO_2 emissions, which are the major contributor of visibility impairment in the Class I areas located on the Colorado Plateau. At the conclusion of the Transport Commission's studies, the Regional Haze program transitioned into a program directed by the Western Regional Air Partnership (WRAP), which consisted of representatives from regulatory bodies, environmental groups, industry and the tribes. The efforts of the WRAP focused on the perceived success of the Acid Rain Market Trading Program, and relied on a regional SO_2 milestone and backstop market trading program. Initial Regional Haze Rules were issued by the EPA in 1999, and following the outcome of lawsuits initiated against the 1999 rules, final Regional Haze Rules were issued in 2005. PacifiCorp began implementing its emissions control plan at that time.

The goal of the Regional Haze program is to show "reasonable progress" towards achieving natural visibility conditions in specific Class I national parks and wilderness areas by 2064. The first step towards meeting this goal is for Best Available Retrofit Technology (BART) eligible units to install BART controls. The Regional Haze program and respective state compliance plans were developed with the expectation that BART controls would be installed on the BART eligible subset of units from 2008 through 2013.

With respect to the Company's future projects, commenting parties assume that there is near term certainty regarding the requirements and timing for compliance with each of these emerging regulations. The Company has included discussion of emerging environmental regulations and legislation with the potential to affect future PacifiCorp operations in the IRP that is currently under consideration by the Commission. However, there is a great deal of uncertainty associated with many of these emerging requirements. Attempting to analyze multitudes of hypothetical compliance scenarios without specific information pertaining to potentially affected areas and/or units, compliance requirements, and compliance timelines would not produce meaningful results, and could not be accommodated in the IRP given its strict filing schedule. This uncertainty is highlighted by President Obama's determination on September 2, 2011, that the EPA should withdraw its pending reconsideration of the ozone standard and, instead, reconsider the standard during the 2013 scheduled review. Although PacifiCorp's fleet of generation assets faces a constantly changing set of environmental regulations and priorities, the Company makes every effort to stay informed of emerging regulations and incorporates appropriate and likely outcomes into its planning process assumptions. For example, the Company is incorporating proxy compliance projects costs and timing in its forward-looking planning efforts, particularly with respect to emerging Utility MACT rulemaking, coal combustion residuals (CCR) rulemaking, and emerging Clean Water Act 316(b) rulemaking. As applicable details regarding other emerging rulemaking processes become available, including EPA's proposed plant effluent rulemaking and more stringent National Ambient Air Quality Standards (NAAQS), proxy compliance projects will be incorporated into the Company's planning analyses as well. When making its investment decisions, the Company must balance the interests of its customers and regulatory bodies in each of the six states that it serves. This scenario also differentiates PacifiCorp's regulatory environment from that of the PGE Boardman facility.

As a stand-alone concept, the perceived flexibility afforded by regulations such as the Regional Haze Rules / BART process to shut down individual units to avoid costs prior to compliance deadlines must be balanced against potential customer impacts of pursuing such a scenario on a fleet-wide basis. If that concept were applied to the pending Utility Hazardous Air Pollutant Maximum Achievable Control Technology Standards (HAPs MACT), the near-term compliance deadline for shutdowns would be in early 2015. Unless a company is in compliance with or idles facilities prior to the effective date of the HAPs MACT, Regional Haze Rule compliance flexibility would be irrelevant. Further, plant retirement prior to environmental compliance deadlines assumes that a utility can effectively secure replacement power prior to 2015. However, insufficient existing market capacity and/or transmission system infrastructure, even when coupled with enhanced energy efficiency, may make it impossible or even potentially catastrophic to pursue retirement of facilities before compliance deadlines, if customer loads are expected to be reliably served without significant impacts to rates.

PacifiCorp has committed, however, via the IRP action plan, to continue to assess emerging environmental regulations and their potential impacts on the Company's coal-fired generation resources. The IRP coal utilization case studies were the first step in meeting PacifiCorp's obligation in that regard, involving new model functionality that combines incremental plant investments and coal plant shutdown optimization. In addition, the Coal Replacement Study attached herewith further supplements the IRP coal plant analysis. It should not be presumed, however, that accelerated closure of the Company's coal fueled generation resources is inherently in the best interests of customers. While that outcome would align itself well with the interests of certain commenting parties, the Company's assessments to date have not supported that result. As the Commission is aware, the Company assesses the depreciable plant lives for ratemaking purposes of each of its facilities every five years, with the next assessment scheduled to begin in 2012.

PacifiCorp's emissions control investment program, and investments in individual generation units, cannot be considered in isolation. As discussed in PacifiCorp's IRP, the Company's preferred portfolio outcomes must balance the need to effectively manage its existing generation resources and identify the most appropriate mix of new generation resources to meet its generation capacity deficit. In addition to reducing emissions and maintaining least-cost generation availability from the existing facilities at which it has invested in emissions control equipment, the Company has also avoided increasing emissions by adding more than 1,400 megawatts of non-emitting wind generation between 2006 and 2010. During that same time period, the Company has also invested in natural gas fueled resources, the most significant of which are the Company's Currant Creek block 1 combined-cycle combustion turbine (CCCT) facility that was placed in service in March 2006, the Company's Lake Side block 1 CCCT facility that was placed in service in September 2007, and the Chehalis CCCT facility acquired in September 2008. PacifiCorp has also recently begun construction of the Lake Side block 2 CCCT facility that is scheduled to be placed in service in 2014.

Comparisons with the Boardman Plant

Several of the comments question how PacifiCorp's investments in emissions control equipment compare to PGE's decision to retire and decommission its Boardman facility 20 years earlier than its previously planned service life of 2040. In response to the questions posed, it is important to note that PacifiCorp's comments with respect to the Boardman decision are limited to its understanding of publicly available information pertaining to the decision; PacifiCorp does not have first-hand knowledge of the underlying factors affecting the facility including pending litigation and settlement discussions, Boardman's environmental compliance history, PGE's long-term capacity needs, PGE's transmission system, a plant-specific analysis of other environmental drivers and impacts, or PGE's business plans and priorities. Notably, electricity generated by the coal-fired Boardman plant only supplies approximately 15% of PGE's electricity, as compared to PacifiCorp's larger coal fleet that supplies more than 50% of its electricity. The approved Oregon Regional Haze State Implementation Plan does not avoid all compliance costs associated with emission reductions, nor does it insulate the Boardman plant from incurring additional costs in the event that new environmental regulations are adopted between now and 2020. Likewise, any facility contemplating shutdown in a specified year is not immune from incurring additional compliance costs, regardless of the planned shutdown date, due to changes in environmental regulations. PacifiCorp is uncertain as to the potential impact of such other emerging environmental regulations, including the proposed Utility HAPs MACT, on PGE's Boardman plan.

PacifiCorp wholly-owns or has partial ownership share in 26 coal fueled units within the states of Wyoming, Utah, Arizona, Colorado and Montana. PacifiCorp maintains operational responsibility for 19 of those units. Fundamentally, the goal of PacifiCorp's emissions control plan is to ensure compliance with environmental regulations governing its operations while providing the least cost generation portfolio for customers. PacifiCorp views plant retirement as a consequence or potential result—not the objective—of its evaluation of environmental compliance options.

As mentioned above, PacifiCorp began implementing its emissions control plan in 2005. The initial focus of the plan was on installing controls to reduce SO2 emissions, which are the most significant contributors to regional haze in the western United States. In addition, the Company has installed low NOx burners to significantly reduce NOx emissions. The Company also anticipates completing installation of five SCRs (or similar NOx-reducing technologies) by 2022, further reducing NOx emissions. The Company's emissions control plan includes the installation or retrofit of seven baghouses to control particulate matter emissions. For certain units which utilize dry scrubbers, baghouses have the added benefit of improving SO_2 removal. Baghouses also significantly improve mercury emissions control capability. Figures 1 and 2 represent the reductions in SO_2 and NOx emissions that are expected to occur at units owned by the Company in Wyoming, Utah, and Arizona as a result of the Company's emissions control plan.

Figure 1

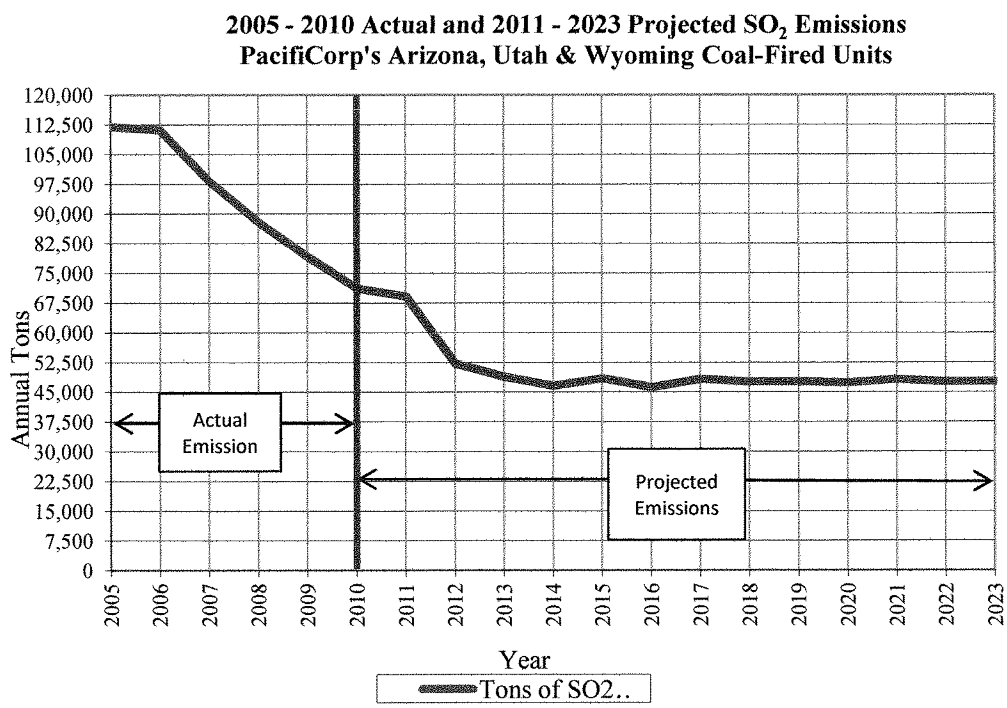
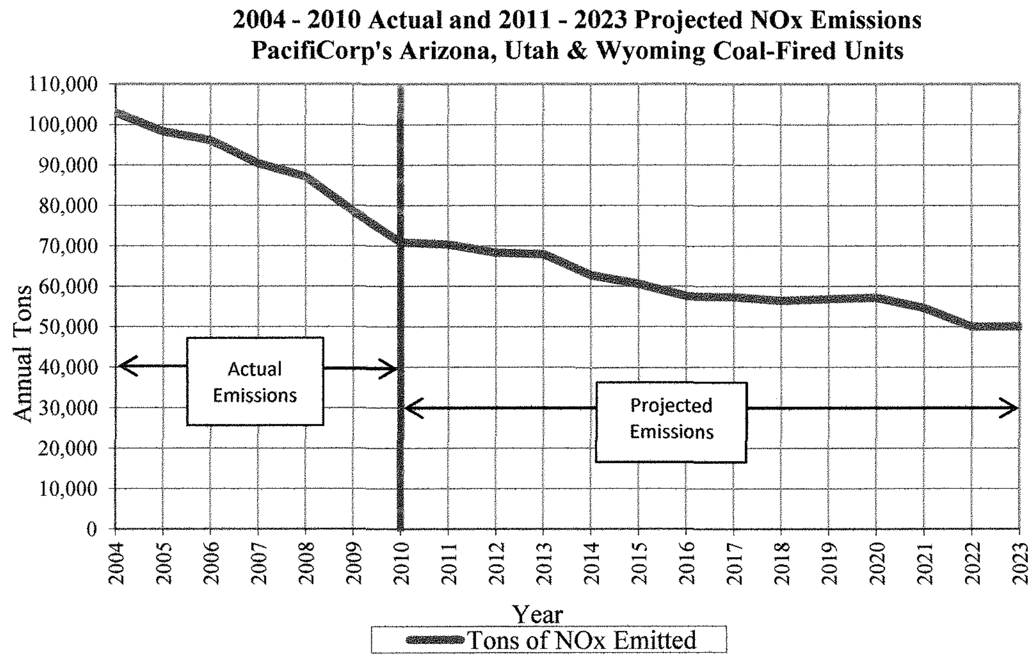


Figure 2



Projects that are currently expected to be required for compliance and their proposed implementation timelines are included in PacifiCorp's current long-term environmental plan. PacifiCorp has spent approximately $1.2 billion on emissions control equipment from 2005 through 2010, with a total capital investment of approximately $2.7 billion expected through 2022 for required projects.[2] It is anticipated that upon completion, those investments will have supported emissions control projects at 15 of 19 PacifiCorp-operated units, affecting approximately 6,700 net megawatts of generation capacity (approximately 5,300 net megawatts PacifiCorp share). However, all projects will be reviewed prior to execution to ensure that they remain economically justified given any environmental regulatory or policy changes that may occur going forward. While the total cost of those emissions control investments is significantly greater than the approximately $500 million referenced for the stand-alone 585 net megawatt Boardman unit, they must be considered on a total system basis.

Energy Efficiency (Class 2 DSM) Resource Analysis

A number of parties commented on whether PacifiCorp included enough energy efficiency in the IRP preferred portfolio. Staff and NWEC provided the most detailed critique of the Company's energy efficiency analysis methodology. Specific observations include the following:

[2] The redacted version of the Coal Replacement Study attached to these comments also considers incremental selective catalytic reduction (SCR) project investments that could be needed through 2030, although no Company commitments or agency actions have been taken that require these projects. The Coal Replacement Study also considers incremental costs for proposed rules for Utility HAPs MACT mercury emission controls, coal combustion residuals and cooling water intake structures, which are incremental to the $2.7 billion figure referenced above.

- NWEC claims that the Company needs to justify its energy efficiency resources in light of a comparison with resource targets included in the Northwest Power and Conservation Council (NWPPC) 6th Power Plan.[3]
- Staff and NWEC state that ramp rates should be more fully explained, and may be limiting energy efficiency selection.
- Staff also suspects that the energy efficiency measure bundling methodology may be limiting selection of resources.

Comparison to the NWPCC 6th Power Plan

In regard to NWEC's point regarding comparison of conservation opportunities and targets between the IRP and NWPPC's 6th Power Plan, it should be emphasized that the use of utility-commissioned potential assessments are more relevant sources of information for resource planning than reliance on regional study data and opportunity estimates. PacifiCorp appreciates the noted differences between energy efficiency opportunities assumed to be available within PacifiCorp's service territory originating from the 6th Power Plan calculator and the opportunities identified for acquisition in the IRP. However, these differences are expected, and that is why the 6th Power Plan calculator instructions contain the following disclaimer:

> *"**Introduction:** The purpose of this calculator is to provide utilities with a simple means to compute "their share" of the Northwest Power and Conservation Council 6th Plan's regional conservation target. This calculator is intended to provide utilities with an "approximation" of the level of conservation they should target in order to be consistent with the Council's regional goals. The Council **does not** formally assign individual utility targets in its planning process. Individual utility conservation goals are best established through utility integrated resource planning processes which can better account for local conditions and legal requirements. Nevertheless, the results of this calculator can be used as rough guidance for utility conservation program planning until such time as a utility completes its own integrated resource plan or other similar process."*

To ensure the Company is cognizant of and considers all possible energy efficiency opportunities available in the construction of its resource plans, PacifiCorp relies on independent third-party assessments of energy efficiency opportunities specific to the customer demographics and loads found in its service areas. Utility territory-specific potential assessments are more indicative of service territory opportunities than broader regional studies. Although regional studies are a fair approximation of total opportunity across the entire region, attempts to break this data down to smaller geographic areas, as NWPCC does with the use of the 6th Power Plan calculator, results in far less accuracy because it is necessary to then assume similarities between utility service territories; hence, the need to include a disclaimer on calculator usage for this purpose.

To help illustrate the differences in opportunity that can exist between a utility's service territory assessment and a regional calculator, refer to Appendix E in Volume II of the Company's 2011 potential study update[4], "Washington Potential in Comparison to the Council's 6th Plan". The differences identified in Appendix E between what the 6th Power Plan calculator identified as

[3] The 6th Power Plan is available from the following Web site: http://www.nwcouncil.org/energy/powerplan/6/default.htm

[4] Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, March 31, 2011. http://www.pacificorp.com/es/dsm.html

PacifiCorp's Washington opportunities and those identified by the Company's commissioned study were not surprising. PacifiCorp had completed a similar analysis that illustrated the differences between the 6th Power Plan and the Company's 2007 potential study results in preparation for the Company's Washington 2010-2019 ten-year conservation forecast and 2010-2011 biennial target report—a Washington Initiative 937 requirement.[5] In that report the Company provided information that showed PacifiCorp's Washington residential customers used, on average, significantly more energy per household than the regional average. With this information the Company was able to demonstrate that it serves 25 percent fewer homes than assumed by NWPCC in the use of the 6th Power Plan calculator and "percent of revenue allocation" methodology. While the Company has more opportunities for savings for some specific measures; i.e. space heating, there is significantly less opportunity for savings from residential lighting, appliances, and consumer electronics. The report also pointed out, among other differences, that the Company's industrial sector load was dominated by one large customer, reducing the acquisition diversity a regional study might assume available in terms of customer participation and investment over time.

While the Appendix E comparison is Washington-specific, it provides evidence as to why the use of utility-commissioned potential assessments are more relevant sources of information for resource planning than regional study data and opportunity estimates.

Ramp Rate Explanation

In response to Staff and NWEC, the Company believes that the ramp rate assumptions adopted for the IRP portfolio modeling reflect prudent consideration of company-specific implementation constraints not accounted for in the potential assessments.

The explanation for market ramp rates is provided on page 50 of the 2010 potential study. A graphical representation of the differing rates is provided on page 51, Figure 17. It is important to note that all market ramp rates "end" at the same place, with 100 percent of the achievable technical potential acquired by the end of the planning period. The ramp rates are not limiting overall acquisition, just realistically constraining amounts for the year in which it is available. The application of ramp rates in the potential study is consistent with the reasons provided in Chapter 4 of the 6th Power Plan, pp. 4-14 to 4-20, including:

> "*The second constraint is annual deployment, which represents the upper limit of annual conservation resource development based on implementation capacity. Such constraints include the relative ease of difficulty of market penetration, regional experience with the measures, likely implementation strategies and market delivery channels, availability of qualified installers and equipment, the number of units that must be addressed....*"[6]

---

[5] PacifiCorp's Ten-Year Conservation Potential and 2010-2011 Biennial Conservation Target for its Washington Service Area, July 2, 2010. The report is available for download using the following Web hyperlink: http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Washington/Regulatory_Filings/DSM_I_937_Compliance_Filing/01-29-10_DSM_I_937_Compliance_Filing/Filing/Initiative_I-937_Report_Ten-Year_Conservation_Potential_2010-2011_Biennial_Target.pdf

[6] 6th Power Plan, p. 4-15

Ramp rates for the Energy Trust of Oregon (ETO) resources are incorporated in their annual deployment scenario, which was described in the response to Staff data request 129 and the accompanying supplementary response. To summarize, the ETO begins with a 'frozen efficiency' baseline of commercially available technical resource over twenty years and adds yet to be identified new technologies that may be available toward the end of the planning period. The Energy Trust assigns technical availability ramp rates to five year periods throughout the planning horizon. Then, rate of availability of this technical potential is differentiated in five year blocks. The achievable potential acquisition ramp rates, called the Energy Trust deployment scenario, in the first five years are informed primarily by the program delivery team. Ramp rates for the subsequent fifteen years are informed primarily by the Energy Trust's planning department. The application of ramp rates is comparable to the achievable percentages used in PacifiCorp's study performed by Cadmus, i.e., they are an estimate of the total available resource that can be acquired.

<u>Supply Curve Bundle Methodology</u>
Regarding Staff's contention that the Company's aggregation of energy efficiency measures into bundles may restrict resource selection, PacifiCorp notes that its approach was designed to minimize such resource selection bias with the recognition that the model can accommodate only a limited number of bundles.

The Company's use of supply curve bundles by levelized costs is discussed on pages 141-142 of the IRP. As described on page 142, the Company created nine cost bundles for capacity expansion modeling, three more cost bundles than developed for the 2008 IRP. The purpose of the more granular representation was to improve modeling results by removing barriers to resource selection that may occur if the measure cost bundles were too broad; for example, to avoid a bundle being rejected by the System Optimizer model due to the higher-cost measures in that bundle that the model would find uneconomic.

The size and range of the cost bundles vary, but as previously noted these variations are by design. The bundles are more granular (less difference between the low and high costs in the bundle) at the lower end of the cost spectrum. This is to help ensure energy efficiency resource selections are as precise as possible in the range that surrounds what the 6th Power Plan refers to as "the cost effectiveness limit for conservation" more fully described in Appendix E of the 6th Power Plan.[7] The added granularity of the bundles in the area where the cost effectiveness limit is likely to be found is designed specifically to maximize the resource selections, not limit them.

The 6th Power Plan also bundles measures together. However, the NWPCC's price bundles are by technology, sector and application mode. While the approach is slightly different, PacifiCorp's method follows the same strategy where like measures are grouped together and distinctions are preserved for vital analytical purposes, such as selection by levelized costs.

Distribution Energy Efficiency

In Order No. 10-066, the Commission acknowledged the Company's 2008 IRP but included an additional action item to incorporate an assessment of distribution efficiency potential resources

[7] Ibid, E-5.

in its next IRP. Staff states that the Company has not fully complied with this action item because: (1) the System Optimizer sensitivity scenario study indicated that conservation voltage reduction (CVR) is cost-effective and therefore should be acquired system-wide; and (2) if CVR resources had been included in the preferred portfolio, it would have affected resource selection. Staff then recommends the following modifications to PacifiCorp's current CVR action plan item:

- Begin acquisition of a CVR project in PacifiCorp's Washington service area in 2012 and complete the project no later than 2018.
- To acquire all of the available cost-effective CVR throughout its service area by 2022. This action item will be based primarily on information from Yakima and Walla Walla service areas. Cost-effectiveness analyses should follow the same methodology as the modeling approach used in the Class 2 DSM decrement assessment in the 2011 IRP Addendum.

In order to provide context and background, below is a summary of CVR action item discussions held with Oregon stakeholders in mid-June 2010.

PacifiCorp held an Oregon IRP stakeholder meeting on June 16, 2010. At this meeting, attended by Staff, the Company described its on-going distribution efficiency activities (such as voltage setting practices and reconductoring) and discussed expectations and compliance options for the CVR action item. The Company outlined two approaches for addressing the action item: (1) extrapolate findings from R.W. Beck's Distribution Efficiency Initiative (DEI) study with the understanding that resulting estimates would not be valid as acquisition targets; and (2) conduct its own resource potential and cost-benefit study, structured as a multi-year staged approach, to first gain evaluation and implementation experience with a limited number of circuits (in Washington) and then apply findings on a system-wide basis.[8] Staff stated at that time that either approach was valid. PacifiCorp thus proceeded with its preferred approach—the multi-year phased study—for meeting the action item requirement. To demonstrate progress for the 2011 IRP, the Company proposed to test the System Optimizer resource set-up and selection impact of a "trial" Washington CVR resource provided by the consultant for the Washington CVR study, Commonwealth Associates, Inc. Because the data were preliminary and not validated by the Company, the resource testing was never meant to prove the cost-effectiveness of the resource or draw conclusions regarding energy savings scalability to other load areas.[9]

<u>CVR Acquisition on a System-wide Basis</u>

PacifiCorp remains concerned that CVR is inappropriate as a candidate preferred portfolio resource option for the IRP because the resource's achievable potential and supply-cost relationship cannot yet be determined so that appropriate resource options can be developed and modeled for each state. Without this critical information, the Company does not believe that CVR can be evaluated on a consistent and comparable basis with respect to other resources.

[8] In terms of preliminary project scheduling, the Company stated that the implementation of any CVR projects in Washington would begin no sooner than 2012, followed by consideration of Oregon circuits no sooner than 2013.

[9] For example, the load shape for the CVR resource came from the R.W. Beck study, and was not validated as being reasonably representative of the Washington feeders evaluated for the study.

PacifiCorp also emphasizes that in response to a Staff data request[10], the Company strongly cautioned against extrapolating CVR study results to other parts of the system. Continuing engineering and financial due-diligence of the studied circuits indicates that some circuit solutions may prove to be nonviable. As noted in responses to data requests, the Washington CVR study is still undergoing review and has not been fully vetted as part of the Washington Energy Independence Act (RCW 19.285) compliance process.[11]

Staff's Recommended CVR Action Item Recommendations

Concerning Staff's action item recommendations, the Company objects to mandating project commitment dates for situs resources in other states, and based solely on a cursory resource "extrapolation" analysis with identified flaws and unfounded assumptions. PacifiCorp has approximately 2,180 active primary distribution circuits throughout its system compared to the 19 circuits evaluated for the Washington CVR study. Analyzing these circuits will be costly. A realistic timeline for implementing CVR resources on such a massive scale is unknown, and must account for availability of firm cost, benefit, and impact estimates, states' willingness to pay for the studies and resources, the Company's budgetary priorities, staff resources, stakeholder vetting, technology advancements (e.g., smart grid and penetration of other energy efficiency measures), and various regulatory processes and approvals.

With this said, PacifiCorp proposes to work with Staff to develop a modified CVR action item using PacifiCorp's draft CVR implementation plan as the basis. This implementation plan, included as Appendix 1 of this document, provides the planning specificity desired by Staff and covers activities for the next two years—an appropriate timeframe for the action plan.

Load Control (Class 1 DSM) and Price Response (Class 3 DSM) Resource Analysis

Staff notes that PacifiCorp excludes Class 3 DSM from the preferred portfolio and includes "only a minimal amount" of Class 1 DSM. Staff cites the new DSM potential study, which indicates achievable technical potentials of 536 MW of Class 1 DSM and 357 MW of Class 3 DSM by 2030. However, the preferred portfolio includes an average of 160 MW of Class 1 DSM and no Class 3 DSM. NWEC also states that the IRP action plan calls for "very minimum amounts" of Class 1 DSM. NWEC continues that:

> In fact, although the Action Plan appears to call for 250 MW of Class 1 DSM, only 80 MW appear to be a firm commitment from the Company as the Action Plan goes on to state the remaining 170 MW identified for the 2011-2020 period will be pursued 'depending on final economics'.[12]

NWEC states that it could not find any explanation for lowered expectations in irrigation load control program capacity. More detailed information is necessary to evaluate whether the 2011 adjusted resource expectations are justified.

[10] PacifiCorp response to Staff data request 155.
[11] For example, a study recommendation is to select the final implementation group of circuits after all circuits originating on a substation transformer have been studied for voltage optimization (footnote final report, page 10).
[12] NWEC Comments, p. 6.

Class 1 and Class 3 DSM in the Preferred Portfolio

Regarding acquisition of Class 1 DSM resources, Staff and NWEC are overlooking the contribution of the Company's existing Class 1 programs to the overall resource potential. The Company's existing Class 1 resources (loads already under management) include 324 MW of combined residential air conditioning and irrigation load management resources. The 2011 IRP selected, pending final economics, an additional 250 MW of Class 1 resources.[13] With the additional selections the Company is effectively pursuing 575 MW of the 623 MW of Class 1 resources identified in the Cadmus study, or 92 percent of the achievable technical potential before accounting for any percentage of the opportunity that is uneconomic.

PacifiCorp also notes that updated potentials study actually identifies 623 MW of Class 1 DSM (536 MW in the east and 87 MW in the west) and 514 MW of Class 3 DSM (357 MW in the east and 157 MW in the west). The 2011 IRP selected 250 MW of Class 1 DSM additions (187 MW in the east and 63 MW in the west).

Concerning Class 3 DSM, as explained on page 139 of the IRP, "[i]n providing the data for the construction of Class 3 DSM supply curves, the Company did not net out one product's resource potential against a competing product". To illustrate how resource opportunities may be impacted had this been done, consider that the Class 3 resource opportunities are dominated by an assumed "mandatory" irrigation time-of-use program. The potential study showed that the opportunity for the mandatory time-of-use program might be as high as 307 MW, or 60 percent of the overall Class 3 opportunity identified in the Cadmus assessment. However, this capacity would completely replace the existing voluntary Class 1 irrigation load management opportunity, resulting in no net gain in resource capacity.

Furthermore, many of the Class 3 resource opportunities compete within their own class of DSM. Class 3 commercial critical peak pricing, commercial and industrial demand buyback, and real-time pricing compete with each other for controllable loads. They too are not additive, but rather program alternatives. Although they are treated as additive potential in the Cadmus study and IRP portfolio modeling, the load reduction competition would need to be accounted for if considered as firm resources for planning purposes. As Class 3 DSM resource selections are not included for capacity planning purposes (for reasons explained in the plan; e.g. inadequate firmness and reliability), not taking these product interactions into consideration posed no risk of over-reliance (or double counting the potential) of Class 1 and Class 3 resources in the IRP.

Documentation on Reduced Irrigation Load Control Capacity

Regarding reduced irrigation load control capacity, PacifiCorp provided an explanation in the December 15, 2010 IRP public input meeting report.[14] The Company's estimation of resource contribution from the irrigation load management programs in Idaho and Utah are program impacts based on billing demand data, and in some cases, equipment nameplate ratings of participating customer sites and equipment.

[13] The Company refers NWEC to page 252 of the IRP (third and fourth paragraphs) for a caution against interpreting preferred portfolio and action plan resources as "firm commitments".

[14] The meeting report can be accessed through the following Web hyperlink: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP_PIM5-12-15-2010_MeetingReport.pdf

Between the submissions of the Company's 2008 IRP and 2011 IRP the Company conducted an impact evaluation on the 2009/2010 Idaho irrigation load management program. This information was used to both inform the Cadmus study (for additional irrigation load management opportunities) and existing resource assumption data for the IRP. The realized impact of the program can vary dramatically from year to year, but the results of the two-year impact evaluation revealed that the actual load realized at the time of dispatch was less than the Company had originally assumed for prior resource plans.

Need for a 2016 Combined-Cycle Combustion Turbine Resource

Staff and other parties question the need for capital investments in CCCTs over the next 10 years. Parties claim that capacity requirements can be met with additional DSM, firm market purchases, and more flexible gas resources such as simple-cycle combustion turbines (SCCT). RNP further claims that System Optimizer resource selection is biased towards CCCTs over SCCTs and market purchases, citing PacifiCorp's use of a stochastic cost adjustment that reduces CCCT capital costs.

Resource Alternatives for a CCCT

The Company conducted rigorous system economic modeling to come up with its preferred portfolio. It believes that it has appropriately and fairly represented the costs, availability, dispatch characteristics, and risks of resource options in determining relative cost-effectiveness for meeting load requirements. PacifiCorp argues that the premise that a 600 MW capacity need in 2016 can be made up—reliably and economically—with more DSM and market purchases is faulty. The reasons are as follows:

- PacifiCorp would need to rely on higher-cost energy efficiency (Class 2 DSM). For example, in Staff's "aspirational" portfolio[15], Utah energy efficiency resource costs reach $248/MWh. Staff assumes that the Company could get cost recovery for such high-cost DSM—an outcome with a low probability.
- Class 3 DSM (unless made to be mandatory) is a non-firm resource not suited as a reliable capacity replacement option. There is considerable controversy regarding time-varying rate design and its impacts to customers as evidenced by opening comments on the Commission's straw proposal to investigate mandatory time-varying rates (Docket UM 1415). To assume that Oregon (setting aside other state commissions) would approve mandatory Class 3 DSM programs in time to affect the investment decision for the next major resource is not realistic.
- PacifiCorp described above the issues surrounding extrapolation of energy savings from the limited Washington CVR study. The resource cost assumed for the original IRP sensitivity study and Staff's aspirational portfolio study is likely significantly underestimated due to factors not captured in the consultant's CVR study.

[15] As requested by Staff, the aspirational portfolio forces in (1) a 125 MW mandatory irrigation time-of-use program covering Oregon, Washington, and California, and (2) CVR capacity, ramping up to 48 MW on a system-wide basis by 2020. The System Optimizer model is prevented from adding new thermal resources in 2015 through 2020, and therefore must meet capacity requirements primary with DSM and firm market purchases.

Finally, the Company points out that the IRP action plan again includes the following action item that addresses on-going consideration of resource need and suitability (page 255):

> *PacifiCorp will reexamine the timing and type of post-2014 gas resources and other resource changes as part of the 2011 business planning process and preparation of the 2011 IRP Update.*

This reexamination will be incorporated as part of the all-source Request for Proposals planned for issuance in early January 2012.

<u>CCCT versus SCCT costs</u>
RNP claims that SCCTs are more economical than CCCTs by virtue of lower capital costs. However, the capital cost difference between CCCTs and SCCTs has narrowed significantly to the point where they are almost the same. This cost convergence, driven largely by SCCT demand and significant emission control costs for units near populated areas (such as for Selective Catalytic Reduction (SCR)), is the primary reason why a capital cost adjustment is no longer necessary to induce the System Optimizer model to select CCCTs.[16] Moreover, a comparison of capital costs alone does not capture the cost tradeoffs between these two resource alternatives. CCCTs have a better heat rate and lower variable operation and maintenance cost than SCCTs, which translate into lower operating costs over the life of each asset. Even modest heat rate differences, owing to the 30 to 40 year design life of natural gas resources, can significantly affect life cycle costs. (Refer to the resource cost tables in Chapter 6 of the IRP, for example, Table 6.3.)

Geothermal Resources

ODOE and RNP express dissatisfaction with PacifiCorp's progress on promoting geothermal resources in light of the Company's finding that geothermal resource options were found to be cost-effective in portfolio modeling. Specific recommendations include the following.

- The Commission should require PacifiCorp to conduct a geothermal-only RFP because geothermal power purchases may be cost-effective relative to company self-build options.
- The Company should pursue collaboration efforts with geothermal developers and other stakeholders to address geothermal development risks.

PacifiCorp agrees with the parties that geothermal resources have potential as a clean and cost-effective baseload option if development risks for the Company and its customers can be appropriately mitigated, and can provide other benefits such as renewable resource diversity. It is important to note that the Company has not eliminated geothermal generation from consideration even though this resource was excluded from the preferred portfolio. Page 131 of the IRP summarizes the Company's plans to continue analyzing geothermal opportunities, which is reflected in the IRP action plan on page 254. The Company also indicated in the IRP action plan and at the IRP technical conference on August 9, 2011, that it will continue to include

[16] PacifiCorp recently tested the impact of removing the stochastic cost adjustment from the CCCT capital costs. The Company ran System Optimizer with core case 3 input assumptions and the unadjusted CCCT capital costs. The resulting portfolio resources were identical to the original case 3 portfolio as expected.

geothermal projects as eligible bids in future RFPs. However, PacifiCorp does not believe it is prudent for the Commission to compel it to conduct a geothermal-only RFP. Such an RFP would conflict with the all-source RFP planned for issuance in January 2012; any geothermal resource selected in a geothermal-only RFP would need to be justified in terms of both need and cost relative to final bids selected from the all-source RFP. Additionally, at least one northwest utility indicates that a geothermal-only RFP approach may not be effective for acquiring these resources at the present time due to the lack of viable, cost-effective resources.[17]

Capacity Planning Reserve Margin Determination

Staff, ICNU, and ODOE commented on PacifiCorp's target capacity planning reserve margin (PRM). Staff and ICNU identify perceived shortcomings of PacifiCorp's Loss of Load Probability (LOLP) study and decision to change its capacity planning reserve margin from 12 percent to 13 percent. Staff cites the following:

- The Company failed to consider the reliability benefits of non-firm transmission capacity.
- PacifiCorp did not compare the marginal benefits of different planning reserve margins.
- Using simple-cycle combustion turbines (SCCTs) is a shortcoming for marginal cost analysis of a range of PRMs.

ICNU cites the following:

- The Company did not properly model the Northwest Power Pool's Contingency Reserve Sharing Program (CRSP).
- The Company did not account for the impacts of proposed regional market coordination initiatives, such as the Joint Initiative.
- The Company did not incorporate spot market purchases as a potential resource in light of surplus hydro energy available in the Northwest.
- The Company should have evaluated unserved energy as well as LOLP, and more carefully considered the impact of incremental resource location and type on Loss of Load Hours.

<u>Reliability Benefits of Non-firm Transmission Capacity</u>
Regarding Staff's comment that the Company failed to consider the reliability benefits of non-firm transmission capacity, PacifiCorp agrees that non-firm transmission capacity may be used on an operational basis to address emergency situations to the extent the non-firm transmission is available. However, a resource planning principle that has been in effect for many years—and which has been accepted by all state commissions—is that the transmission system should be modeled based on firm transmission rights in line with serving retail customer loads reliably. Both the LOLP study and IRP portfolio modeling are consistent in this regard. The Company believes there is merit in discussing the role of non-firm transmission in the IRP, but deviating from current modeling practice is a major change that would need to be carefully considered by the Company as well as other state commissions and stakeholders as part of the public input process.

[17] For example, see Idaho Power Company's press release on the outcome of their 2008 geothermal RFP, which can be accessed with the following hyperlink:
http://www.idahopower.com/NewsCommunity/News/mediaCenter/NewsReleases/showPR.cfm?prID=2010

Marginal Cost Analysis of Reliability Resources
Concerning marginal cost analysis and the use of SCCTs as the proxy reliability resource, the Company first acknowledges that the LOLP study was not designed to assess the trade-off between reliability and costs/benefits. This is stated in the introduction to the study.[18] PacifiCorp conducted marginal cost analysis for the 2011 IRP and prior IRPs. The problem with such analysis is that estimates of the cost of unserved electricity are widely variable and controversial, and the marginal utility of a megawatt of additional reliability is inherently subjective. As a review of PacifiCorp IRP history on this issue will indicate, certain stakeholders see proof that a given PRM is too low while others see proof that it is too high. In adopting a one day in 10 year LOLP criterion, the Company selected an objective resource adequacy measure that is commonly used for resource adequacy studies throughout the electric utility industry. In regard to the use of SCCTs as the reliability resource, this is a standard practice for this type of study. Meeting a PRM level, in practice, is done with a variety of resource types. The costs of meeting a given PRM with different resource mixes are captured in the portfolio modeling.

Finally, the Company notes that Staff significantly overestimates the capacity impact of a one-percentage-point change in PRM. The difference between a 12 and 13 percent planning reserve margin is about 90 MW, not 150 MW as cited in Staff's comments. Reserves are not held for Class 1 DSM, firm market purchases, and firm interruptible loads.

LOLP Study Technical Issues
ICNU recommends that the Commission not acknowledge the LOLP study because of the deficiencies summarized above. Regarding the modeling of power pool contingency reserves, PacifiCorp stated that modeling the CRSP would be complex and not practical to implement for the IRP.[19] Rather than excluding the CRSP benefit from the study, PacifiCorp used the Public Service Company of Colorado (PSCo) PRM impact estimate for the Rocky Mountain Reserve Group's reserve sharing program. Ventyx conducted the LOLP study for PSCo using the same production cost model that PacifiCorp uses. While PacifiCorp intends to work with Ventyx to model CRSP for the next LOLP study, there is no basis to conclude that "proper modeling could reduce PacifiCorp's estimated planning reserve margin"[20] to a greater extent than the PSCo/Ventyx PRM reduction estimate.

ICNU also states that PacifiCorp should have considered on-going collaborative regional initiatives in the LOLP study, or at a minimum, defer analysis of a PRM target until all coordination initiatives are sorted out. As noted in Chapter 4 of the IRP, these initiatives are in their early stages. Costs, benefits, and impacts of specific initiatives have yet to be demonstrated or quantitatively characterized in a fashion suitable for system modeling. If this same logic was applied to the Company's wind integration cost analysis, then it would likewise defer the next wind integration study for similar reasons, which would be unacceptable to many stakeholders.

ICNU's criticism that PacifiCorp should have considered spot market purchases as a reliability resource does not comport with capacity adequacy planning principles adopted by PacifiCorp and other electric utilities. While the Company's IRP models simulate the buying and selling of energy for system balancing purposes, spot market purchases are considered a non-firm resource

[18] 2011 IRP Volume II, Appendix J, p. 245.
[19] 2011 IRP Volume II, Appendix J, p. 252.
[20] ICNU Comments, p. 6.

unsuitable for inclusion in the determination of capacity positions. Further, excess energy available in May and June due to surplus northwest hydro generation does nothing to address system coincident peak capacity requirements that occur in late July.

Finally, ICNU's comments on the impact of incremental resource location and type on Loss of Load Hours have merit. The Company intends to investigate, with Ventyx support, improvements to the LOLP estimation methodology to better integrate System Optimizer capacity expansion capabilities and stochastic production cost modeling.

Transmission Planning and Energy Gateway

Three parties provided comments on transmission planning and Energy Gateway justification:

- Staff states that PacifiCorp provided no evidence that the Sigurd-Red Butte project, for which the Company has requested acknowledgment in the IRP, was evaluated against alternatives, such as a line with different voltage or a local generation resource.
- ODOE calls for PacifiCorp "to better justify the Energy Gateway transmission project and relative investment scenarios."
- NWEC expresses concern that Energy Gateway has not been subjected to a thorough non-transmission alternatives assessment.
- NWEC recommends that the OPUC require the Company to adopt a new transmission planning framework for the next IRP that mirrors the planning process outlined in Federal Energy Regulatory Commission (FERC) Order 1000.

<u>Sigurd-Red Butte Project</u>
PacifiCorp appreciates the constructive comments from the parties regarding the Company's Energy Gateway transmission expansion program. Staff's observation that it "found no evidence that the Company had evaluated any alternative to the proposed [Sigurd to Red Butte] single circuit 345 kV line" is fair given the level of detail provided in the IRP. However it should be noted that the line will allow for additional bi-directional transfers across WECC Path TOT 2C and is needed—at its planned voltage and capacity—to fulfill the Company's transmission tariff obligation to deliver designated third-party network customer resources to growing network loads. Staff's suggested alternatives, including a new generating resource near the Red Butte substation, are not viable given the Company's reliability obligations. It is not a valid option to add a PacifiCorp resource at Red Butte to serve third-party network customer loads, which represent the majority of load in that area.

<u>Non-transmission Alternatives Assessment</u>
It is important to note that Energy Gateway is the overall expansion program and, as is noted in the Transmission Planning chapter of the IRP (Chapter 4, page 63), each Energy Gateway segment will be justified individually based on a combination of benefits. These benefits include net power cost savings, reliability, capital offsets for renewable resource development in low-yield geographic regions, and system loss reductions. Each segment continues to be re-evaluated during the Company's annual business plan and IRP cycles to ensure optimal benefits and timing before moving forward with permitting and construction. Segments could be deferred or not constructed, depending on conditions or alternatives, if evaluations prove the need or timing has shifted.

NWEC notes that the Company is exploring joint development opportunities with Idaho Power and PGE on their proposed Boardman to Hemingway and Cascade Crossing projects, respectively, and that these projects are being considered as an alternative to the Company's proposed Hemingway to Captain Jack project. NWEC suggests that the IRP fails to address the main purposes of these lines as well as what reliability, congestion and/or renewable energy objectives these projects will meet. As is noted in the *Transmission Expansion Action Plan* chapter of the IRP (Chapter 10, page 288), the purpose of the Hemingway to Captain Jack project is to "significantly improve the connection between PacifiCorp's east and west control areas and to help deliver more diverse energy resources to serve PacifiCorp's Oregon, Washington and California customers." As with all Energy Gateway segments, the benefits of the Hemingway to Captain Jack project will be thoroughly evaluated before the Company pursues investment in permitting and, ultimately, construction. Should the system and customer benefits of the alternative proposed projects exceed those expected from the Hemingway to Captain Jack project, it would be prudent for the Company to pursue these options instead. Until that time, additional details on the projects proposed by Idaho Power and PGE are available in their IRPs and internet resources.

Transmission Planning Framework

Finally, NWEC recommends that the Commission require for the Company's next IRP a new transmission planning framework consistent with the principles and requirements of FERC Order 1000. As a FERC-jurisdictional transmission provider, PacifiCorp is subject to compliance with Order 1000 and is in coordination within its planning sub-region and with inter-regional planning entities to develop and implement open planning processes consistent with Order 1000. The Company will then determine, at the appropriate time, how best to assimilate aspects of the FERC Order 1000 planning process into the IRP in light of PacifiCorp's broader resource planning framework, and considering state IRP standards and guidelines and impacts to IRP filing schedules.

Wind Resource Costs and Capacity Factors

NWEC and RNP address wind resource costs in their comments. NWEC questions why wind resource costs are "slightly higher" in the 2011 IRP relative to the 2008 IRP despite the Company's statement that wind turbine prices have come down since the 2008 IRP was published. RNP outlines criticisms on how PacifiCorp derived its wind capital costs. For example, in reaction to PacifiCorp's approach of adding significant amounts of wind resources to the preferred portfolio as a hedge against policy risk, RNP claims that PacifiCorp applied skewed wind resource assumptions that "prevented the Company's model itself from producing portfolios with appropriate levels of wind energy."[21] Specifically, RNP asserts that wind resources are unjustifiably assigned incremental transmission costs associated with the Energy Gateway transmission projects, and that this cost assignment unfairly constrains wind resource selection by the System Optimizer model. RNP also asserts that wind capital costs are too high by virtue of: (1) a "flawed" wind integration cost: (2) the Company's even distribution of resource quantities by cost level; and (3) incorporation of other costs not documented in the 2011 IRP. Finally, RNP states that PacifiCorp's generic wind capacity factors appear low in comparison to other data, such as the Northwest Power and Conservation Council.

[21] RNP comments, page 15.

Wind Capital Cost Trend

Regarding NWEC's comment on wind capital cost trends, the IRP shows declining—not increasing—costs relative to those published in the 2008 IRP. For example, Table 6.4 in the 2008 IRP reports a base wind capital cost of $2,566/kW (2008 dollars) for east-side resources. In contrast, Table 6.5 of the IRP reports a base wind capital cost of $2,239/kW (2010 dollars) for east-side resources. PacifiCorp is not clear how NWEC is making its cost comparison, but suspects that it is incorrectly using the "low" capital cost estimate in Table 6.2 of the 2008 IRP as the basis for the comparison.

Assignment of Energy Gateway Investment Costs to Wind Resources

RNP's characterization that PacifiCorp inappropriately assigned Energy Gateway transmission costs to wind resources is incorrect. The Company only assigned the incremental transmission costs needed to interconnect the wind with the grid, not the Energy Gateway segment costs. The IRP mentions that this cost assignment was accomplished with the use of "wind-generation-only" transmission bubbles in certain cases. For Energy Gateway scenario 1, which only includes the Energy Gateway Central segments, a large investment in west-side transmission would be needed to support at least 500 MW of additional wind in Washington and Oregon. As discussed on page 128 of the IRP, PacifiCorp did not use a wind-generation-only bubble to assign costs for this transmission scenario; rather, a cost adjustment was applied to the total portfolio PVRR after the model determined the portfolio solution. As a result, neither the Energy Gateway transmission costs nor the west-side incremental transmission cost adjustment applied for Energy Gateway scenario 1 had any effect on the quantity of wind selected by the model.

Wind Capital Cost Levels

Regarding RNP's claim that wind capital costs are too high, PacifiCorp makes the following observations in response to RNP's specific criticisms. First, the wind integration cost is a small component of the overall wind resource cost. Factors such as federal renewable production tax credit assumptions, CO_2 regulatory uncertainty, renewable portfolio standard requirements, and forecasted natural gas prices overwhelm any wind selection impacts resulting from changes in the wind integration cost. It is also important to recognize and put into context the inherent imprecision in representing wind integration costs in long-term resource planning models. For example, capacity expansion optimization models, like System Optimizer, are not capable of dynamically adjusting the wind integration cost based on the wind penetration level. Ideally, resource selection would account for the positive, nonlinear relationship between integration cost and capacity penetration. In the case of "Green Resource Future" and other similar IRP scenarios, a higher wind integration cost would then come into play. For these reasons, PacifiCorp disagrees with RNP that the wind integration cost is important for the selection of wind resources. On PacifiCorp's wind integration study itself, the Company believes it is premature for RNP or other parties to claim that PacifiCorp's wind integration costs should be significantly less than the value published in the 2010 study. As discussed in the next section, the Company intends to investigate concerns raised by the parties in the next wind integration study.

Second, the Company notes that the distribution of wind quantities by cost level is inconsequential for wind resource selection because of the number of wind capacity blocks available for model selection at the lowest cost level. As shown in Table 6.10 (far right column), the number of blocks available at "cost level 1" far exceeds the amounts of wind selected in the

IRP portfolios. PacifiCorp acknowledges that the cost-supply relationship for wind characterization is important, and expects to continue improving this aspect of resource modeling as more study data becomes available.

Third, PacifiCorp has incorporated legitimate costs for wind resources, and has provided thorough documentation for these costs in responses to RNP data requests provided well before the due date for party comments. RNP provided no feedback on this cost information in their comments. PacifiCorp is therefore not clear how RNP reached the conclusion that cost elements not documented in the IRP contribute to capital costs that are too high.

In regard to RNP's claim that wind capacity factors are too low relative to other data sources, PacifiCorp notes that the actual average capacity factor for PacifiCorp west-side owned and contracted wind resources is 28.5 percent.[22] There is no basis to conclude that using alternative data sources yields a more credible generic capacity factor than what the Company is presently using.

Wind Integration Study

RNP, NWEC, and ODOE comment on PacifiCorp's 2010 wind integration study. RNP and NWEC believe that the Company did not meet expectations for the wind integration set forth as an additional action item in Order No. 10-066: "By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process." The key comments by these parties are as follows:

- RNP claims that the Company did not address alleged technical flaws brought to its attention that result in cost overestimation, and did not provide sufficient time for stakeholder and PacifiCorp data verification prior to final study completion.
- ODOE mentions its concern with the validity of using National Renewable Energy Laboratory (NREL) proxy data to represent output for missing sites.
- Most parties advocate that the Company use an independent technical review committee as part of the public input process.

Overestimation of the Wind Integration Cost and Data Verification

The Company will continue to investigate methodological concerns raised in the public input meetings and written comments for the next wind integration study. However, it is premature to claim that PacifiCorp's wind integration cost should be significantly less than the value published in the 2010 study. The Company also reiterates that it responded to the issues RNP raises in this round of comments at the time the 2010 Study was being performed.[23]

Regarding concerns on the handling of the public process and data verification, it should be stressed that wind integration analysis is an evolving activity for the Company and electric utility industry in general, and that PacifiCorp developed a fundamentally new methodology in

[22] The actual average capacity factor accounts for the following resources: Marengo 1 and 2, Leaning Juniper, Goodnoe Hills, Wolverine Creek, and Combine Hills. The average is weighted based on plant installed capacity.
[23] Replies to several RNP issues are available on PacifiCorp's Wind Integration website: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp-ResponsetoSupplemental-RNPComments_6-21-10.pdf

response to comments from the prior wind integration study. It took much longer than expected to analyze data, develop simulated data for wind resources, create and test the wind reserve estimation model in coordination with the Company's technical advisor, and perform the numerous production cost simulations. With commitments for the public process and firm deadlines to incorporate study results in IRP portfolio modeling, the Company nevertheless achieved its study objectives and produced a wind integration cost reflecting important methodological improvements over previous study efforts.

Based on this experience, and the expectation that the complexity of wind integration analysis will only increase over time, the Company does not agree that the Commission should set a firm deadline for the study so that the Company has the latitude to report wind integration study results as an IRP supplement. Not having to constrain the study timeline to meet PacifiCorp's strict IRP filing deadline will enable the Company to address methodological challenges, perform more rigorous data validation, and better accommodate technical review committee activities. [24]

PacifiCorp also continues to emphasize that while wind integration is important from operational and rate-making perspectives, it currently has a negligible impact on the Company's long-term wind resource acquisition strategy.

<u>Technical Review Committee Establishment</u>
The Company intends to establish a technical review committee as indicated in Action Item 8 in PacifiCorp's IRP action plan (page 257). The Company disagrees with RNP's recommendation that the committee's members must be approved by Staff (or NREL staff) on the basis that this is unnecessary. Nonetheless, the Company will consider recommendations from parties with regard to individuals that might be well suited to serve as a committee member.

Renewable Portfolio Standard Compliance Strategy

ODOE believes that the IRP is "the appropriate place to discuss plans to sell RECs [Renewable Energy Certificates], to acquire unbundled RECs, and to follow other RPS compliance strategies."[25] ODOE also advocates that the Company evaluate alternative RPS compliance strategies on a long-term basis in line with the Commission's requirement for Portland General Electric Company to do so.

PacifiCorp agrees with ODOE on these points, and will expand the next IRP to include discussion of RPS compliance strategies and the role of REC sales and purchases. However, the Company needs to be cognizant of the impacts of disclosing confidential information in IRP documents and public meetings pertaining to RECs, and will need to coordinate information prepared for the IRP with that provided in various state RPS compliance reports. PacifiCorp also notes that the IRP action plan already includes an action item on RPS compliance strategies. (See page 255.)

---

[24] PacifiCorp is mandated by commission orders in other states to file the IRP within two years of the last filed IRP. In such states as Utah and Washington, the Company has received commission approval to file its IRP by March 31 of every odd numbered year.
[25] ODOE Comments, p. 4.

4. CONCLUSION

PacifiCorp respectfully requests that the Commission acknowledge the 2011 IRP, and consider it in the context of balancing customer interests across an extensive and capital-intensive portfolio of generation and transmission assets, recognizing PacifiCorp's continued commitment to meet the Commission's IRP guidelines, meet the IRP action item obligations, and utilize the IRP process to ensure that the best interests of PacifiCorp's customers are protected.

Appendix 1: Draft PacifiCorp DEE/CVR Implementation Plan

2011

1. Complete Tier 1 study in Washington (Commonwealth Associates)
   - Analysis of 19 out of 121 total circuits in the state of Washington. **(COMPLETE)**
2. Provide initial cost input into 2012 general capital budget 10-Year Plan. **(COMPLETE)**
   - Annual placeholder year provided for CVR capital implementation projects in Washington.
3. Prioritize all potentially viable Tier 1 Washington circuits for implementation strategy:
   - Account for customer class mix, projected energy savings, cost factors.
   - Study impacts of adjacent circuits and incorporate corresponding costs and benefits.
   - Create detailed estimates for 2012 projects.
   - Develop methodology to communicate measured energy savings to WUTC.
4. Develop parameters to compare (Tier 2) Washington circuits for DEE potential. **(IN PROGRESS)**
   - Forecast aMW saved (Tiers 1 and 2) for 10-year target for Washington.
5. Review best practices for additional energy savings methods and apply where applicable. **(IN PROGRESS)**
6. Provide Commonwealth study to the WUTC DSM Advisory Group (meeting tentatively early October).
7. Identify Washington Tier 2 circuits that show best potential and marginal potential for cost effective, reliable and feasible energy savings.
   - Issue RFP for 2012 fielding and studying identified Tier 2 best and marginal circuits.
8. Provide DEE/CVR data (study findings, aMW savings commitment and implementation plan) to Pacific Power Regulation.
9. Develop Washington Commission communication on progress to date.
10. Develop Oregon Commission communication on progress to date.

2012

1. Complete Washington Tier 2 study (bid out), currently estimated at 12+ circuits.
   - Compare Tier 2 study's predicted aMW to internal 2011 forecast values.
2. Fund and communicate to the responsible manager the Washington Tier 1 highest priority projects.
3. Inaugurate and track measurement and verification for compliance in Washington.

- Develop operating procedure (Smart Grid, Metering, Field Ops, Dispatch, Area Engineering).
- Train as needed (field ops, engineering, IT, etc.).

4. Complete the approved Washington 2012 Tier 1 projects within budget.
5. Review results of Tier 2 study and YTD actual Tier 1 spend.
   - Reprioritize best and marginal Tier 2 circuits with remaining Tier 1 circuits, by highest aMW predicted savings.
   - Provide initial cost input into Pacific Power's 2013 general capital budget 10-Year Plan.
6. Develop 2013-17 capital projects on highest energy savings circuits.

PACIFICORP

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

2011 Integrated Resource Plan

Redacted Supplemental Coal Replacement Study

Let's turn the answers on.

September 21, 2011

This document contains confidential information, and is provided subject to the terms and conditions of protective orders issued by state regulatory commissions for their respective PacifiCorp 2011 Integrated Resource Plan acknowledgment proceedings.

For more information, contact:
PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
http://www.pacificorp.com

This report is printed on recycled paper

Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
Wind Turbine: *Dunlap I Wind Project*

TABLE OF CONTENTS

INDEX OF TABLES

INDEX OF FIGURES

This page intentionally left blank

Introduction

This supplement to the 2011 Integrated Resource Plan (2011 IRP) presents the results of additional studies and analysis that examine the prospects of coal resource replacement over the planning horizon (Coal Replacement Study). The additional studies presented herein supplement the results and conclusions drawn from the coal utilization sensitivity analysis described and presented in Chapter 8 of the 2011 IRP. The Coal Replacement Study reflects the following improvements to the coal utilization sensitivity analysis:

- The design of the coal utilization sensitivities was improved to better capture the tradeoff in incremental investment costs planned for existing coal resources and costs for replacement resource options.
- Assumptions for incremental investment costs planned for existing coal resources were updated with the current planning assumptions and expanded to include estimated costs and reasonably anticipated compliance timelines associated with emerging rules for coal combustion residuals (CCR) and cooling water intake structures under §316(b) of the Clean Water Act (316(b)). Costs associated with mercury emissions controls expected to be required under the EPA's proposed Utility hazardous air pollutants (HAPs) maximum achievable control technology (MACT) rulemaking were incorporated into the previous coal utilization sensitivity analysis and continue to be considered in the Coal Replacement Study.
- Assumptions for market prices and potential costs ascribed to carbon dioxide emissions (CO_2) were reviewed to develop a high and low range of future prices and costs that are aligned with current economic conditions and policy developments.

The objective of the Coal Replacement Study is to test how a range of commodity market prices and CO_2 costs along with environmental compliance costs influence the economic tradeoffs that might cause coal resources to be displaced by replacement resources prior to the end of their currently approved depreciable lives. The Coal Replacement Study was performed using PacifiCorp's System Optimizer capacity expansion model, which is traditionally used to evaluate least cost resource portfolios by adding new resources that can meet projected peak load plus a planning margin.[1] For purposes of the Coal Replacement Study, the System Optimizer model was configured to further evaluate whether system costs could be lowered by replacing coal resources requiring incremental capital investments with alternative resource options.

In determining whether replacement resources would lower system costs, the System Optimizer model compares on-going fixed costs for each coal resource with the on-going fixed costs among replacement resource alternatives while considering resource performance and net variable cost differences. The on-going fixed costs for coal resources include incremental investment costs for pollution control equipment, CCR projects, and 316(b) projects. In the event of coal resource replacement, the System Optimizer model also considers decommissioning costs and costs for

[1] The 2011 IRP includes a 13% capacity planning margin.

the recovery of any remaining depreciation expense from incremental investments made prior to decommissioning.[2] If total costs for any given coal resource are higher than the total costs of replacement resource alternatives over time net of any decommissioning costs and costs for recovery of incremental depreciation expense for investments made prior to decommissioning, the System Optimizer model reports the timing and magnitude of idled coal resources and the timing and type of replacement resource additions.

Coal Replacement Study Design

Overview

The coal utilization sensitivity studies documented in the 2011 IRP were performed as a proof-of-concept analysis. In a proof-of-concept analysis, the primary purpose is to validate that new model functionality used to evaluate coal plant idling generates reasonable results under a range of test conditions and produces acceptable simulation run-times. The study was done to pave the way for future refinement of the modeling approach and was not intended to draw conclusions on the disposition of individual generating units within the system.

The Coal Replacement Study advances the proof-of-concept coal utilization sensitivity analysis in the 2011 IRP with design modifications made in two areas. First, the Coal Replacement Study was implemented with an improved representation of potential replacement resource alternatives. Second, existing resources with currently approved depreciation lives that fall within the 20-year planning period were forced to be decommissioned at the end of their depreciable lives. Each of these modifications is discussed in turn below.[3]

Replacement Resource Options

The coal utilization sensitivity analysis in the 2011 IRP allowed existing coal resources to be replaced only by brownfield natural gas combined cycle resources located at the site of the coal unit being displaced. These natural gas resource replacement options were treated as resource betterment options in the System Optimizer model. The resource betterment functionality in the in the System Optimizer model allows for the replacement of a single resource to which it is assigned. In the coal utilization sensitivity analysis, this functionality was used to simplify the model set up while allowing full replacement costs to be captured by encumbering the betterment resource options with decommissioning costs, recovery of any remaining existing depreciation expense, and any applicable liquidated damages for not meeting minimum take provisions in existing coal supply contracts. While this structure simplifies model set up and is suitable for a proof-of-concept analysis, it does not capture the economic trade-offs among a range of potential replacement resource alternatives.

[2] For purposes of the Coal Replacement Study and as referenced herein, costs for recovery of any remaining incremental depreciation expense includes all regulatory costs applicable to rate based capital expenditures.

[3] The Company evaluates the economic life of resources every five years by completing a depreciation study. The next depreciation study is scheduled to be completed in 2012. Stipulated depreciation lives currently used to establish rates in Oregon differ from those currently used to establish rates in other states. For purposes of the Coal Replacement Study, stipulated depreciation lives are based upon those used to establish rates for the majority of PacifiCorp's service territory.

For the Coal Replacement Study, resource retirement functionality within the System Optimizer model was used in lieu of the resource betterment functionality. This change in design allows existing coal resources to be displaced by a wide range of greenfield resource alternatives consistent with the resource options available in the 2011 IRP. The retirement functionality within the System Optimizer model allows replacement costs associated with decommissioning and recovery of any remaining incremental depreciation expense incurred after decommissioning to be assigned directly to the coal resource being displaced. Because these incremental costs can be assigned to the coal resource as opposed to being included as a cost for a specific betterment resource as was done in the coal utilization sensitivity studies, the range of replacement resource alternatives can be broadened. In this way, the Coal Replacement Study allows coal resources to be displaced with greenfield combined cycle resources, greenfield simple cycle resources, demand side management (DSM) resources, and front office transactions (FOT) beginning in 2015, which is currently assumed to be the first substantive environmental compliance deadline.[4,5]

Growth resources were not allowed to displace coal resources in the Coal Replacement Study. Growth resources are included as generic resource alternatives in the out years of the IRP planning horizon – beginning in 2021 in the 2011 IRP. This resource option is intended for capacity balancing in each load area such that capacity planning margins are met in the out years of the planning horizon. Growth resources are used in the IRP to manage simulation run times by simplifying resource selection beyond the first 10-years of the planning period and are ascribed costs that are derived from the forward price curve for power. As such, growth resources do not accurately reflect the true cost or risk associated with the replacement of a resource requiring capital investment or ongoing fixed costs. As such, allowing growth resources to replace coal resources would provide an artificial incentive for the System Optimizer model to decommission coal resources assuming they could be replaced by a generic resource option without appropriate cost metrics.

Intermittent renewable resource alternatives were also not allowed to displace coal resources in the Coal Replacement Study. Intermittent resources such as wind can supply system energy, but are limited in their ability to provide system capacity given the non-dispatchable and intermittent nature of wind resource generation. Because system coal resources provide valuable system capacity, intermittent resources such as wind are not suitable replacement alternatives and were not included as a replacement resource option in the Coal Replacement Study. However, the 2,100 MW of incremental wind resources included in the 2011 IRP preferred portfolio, which mitigate renewable portfolio standard compliance and fuel volatility risk, are included as system resources in the Coal Replacement Study.

Coal Resource Depreciable Life

The 2011 IRP planning horizon covers 20-years extending out through 2030, and the action plan identifies steps that will be taken to secure resource needs for the first 10-years of the planning period. Given that the action plan focuses on the first 10-years of the planning period, and considering that PacifiCorp has no commitments or obligations to decommission existing

[4] FOT limits are set forth in Chapter 6 of the 2011 IRP.

[5] It is anticipated that compliance with pending HAPs MACT rules will be required as early as 2015 for individual generation units.

resources within this timeframe, a modeling assumption was made for the 2011 IRP that no coal or gas plants are shut down during the IRP 20-year planning period. The coal utilization sensitivity analysis in the 2011 IRP allowed coal resources to be replaced by brownfield natural gas resources beginning 2016. However, the coal utilization sensitivity analysis, consistent with the broader assumption adopted in the 2011 IRP, did not address how coal resource replacement might be influenced by plant shut downs tied to their currently approved depreciable lives.

The Coal Replacement Study improves upon this design by capturing resource replacement economics while considering that the end of the currently approved depreciable lives for some coal resources fall within the 20-year planning period. This approach ensures that incremental investment costs assumed for these coal resources are aligned with their currently approved depreciation lives reflected in rates. As such, the Coal Replacement Study incorporates currently approved depreciation lives by forcing three coal plants to be decommissioned within the 20-year planning period. Carbon is assumed to be decommissioned at the end of 2020, Dave Johnston is assumed to be decommissioned at the end of 2027, and Naughton is assumed to be decommissioned at the end of 2029.

Incremental Coal Resource Investment Cost Assumptions

Overview

The coal utilization sensitivity analysis included coal resource capital investments for planned and/or ongoing pollution control equipment identified in PacifiCorp's business plan with Company commitments and/or obligations. These pollution control projects are required to meet best available retrofit technology (BART) requirements under EPA's Regional Haze Rules as implemented by states in their implementation plans and reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), mercury (Hg) and other pollutants. The projects are also expected to support compliance with increasingly more stringent National Ambient Air Quality Standards (NAAQS) that have been and are continuing to be adopted for criteria pollutants and impending Utility HAPs MACT regulations. As such, the coal utilization sensitivity analysis also included investment costs for mercury emissions control projects. The proof-of-concept coal utilization sensitivity analysis assigned these incremental pollution control equipment investment costs to existing coal resources and assigned costs for any remaining recovery of depreciation expenses from the existing coal plant to the natural gas betterment options.

PacifiCorp performed the Coal Replacement Study using updated investment cost assumptions for the pollution control projects described above, and was expanded to include a set of pollution control project cost inputs associated with additional selective catalytic reduction (SCR) costs across the Company's generation units (see Confidential Appendix A for additional details). While no Company commitments or agency actions have been taken that require installation of this expanded list of SCR projects, the costs have been included in the analysis to conservatively capture the effect of potentially significant incremental pollution control capital investments. Other coal resource investment costs considered in the Coal Replacement Study were also expanded to include proxy CCR and 316(b) compliance projects. The coal utilization sensitivity analysis was further advanced by including remaining costs for recovery of depreciation expenses from these incremental investments in the Coal Replacement Study and removing costs for recovery of depreciation expenses from existing coal plants.

As a stand-alone concept, the perceived flexibility afforded by regulations such as the Regional Haze Rules / BART process to shut down individual units to avoid costs prior to compliance deadlines must be balanced against potential customer impacts of pursuing such a scenario on a fleet-wide basis. If that concept were applied to the pending HAPs MACT, the near-term compliance deadline for shutdowns would be in early 2015. Unless a company is in compliance with or idles facilities prior to the effective date of the HAPs MACT, Regional Haze Rule compliance flexibility would be irrelevant. Further, plant retirement prior to environmental compliance deadlines assumes that a utility can effectively secure replacement power prior to 2015. Where there is insufficient existing market capacity and/or transmission system infrastructure, even when coupled with enhanced energy efficiency, to absorb the load served by retiring facilities, it is likely an impossible and potentially catastrophic proposal to pursue retirement of facilities before compliance deadlines, if customer loads are expected to be reliably served. As such, the Coal Replacement Study does not include compliance plan scenarios whereby alternate pollution control strategies are implemented assuming flexibility in the Regional Haze Rules / BART process that would otherwise put individual units at risk of not meeting requirements with a 2015 HAPs MACT compliance deadline. This planning assumption is especially important to those states that have an expressed desire to continue the utilization of coal as a resource.

Investment Cost Assumptions

PacifiCorp has developed and executed its emissions control plan with a focus on maintaining a reasonable balance between protecting the interests of customers while complying with environmental requirements, all in the face of an uncertain regulatory environment. The emission control projects are required to comply with regional haze rules, NAAQS, stand-alone requirements in state implementation plans, BART permits and construction permits enforceable by state laws. The investment projects included in the Coal Replacement Study also further position PacifiCorp to comply with EPA's proposed HAPs MACT rulemaking.

Investment costs considered in the Coal Replacement Study have been expanded to cover projects that would assist in achieving compliance with pending regulations for CCR and cooling water intake structures under §316(b) of the Clean Water Act, as well as costs associated with the incremental SCR installations discussed above. Cost assumptions for CCR projects assume proposed requirements under subtitle D of the Resource Conservation and Recovery Act will be established in 2012 with a compliance deadline of 2017. Cost assumptions for 316(b) projects are based on proposed rules that would require existing electric generating plant cooling water intake structures that have a design capacity of more than two million gallons per day from surface waters reflect the best technology available for minimizing adverse impacts on aquatic organisms.

Table 1 below compares the type and amount of incremental investment costs included in the Coal Replacement Study with those included in the coal utilization sensitivity analysis. Confidential Appendix A to this supplement provides annual investment costs serving as inputs to the Coal Replacement Study.

Table 1 – Summary of Incremental Investment Cost Assumptions

Description	2011 IRP Coal Utilization Sensitivity Analysis	2011 IRP Supplemental Coal Replacement Study
Required SO_2, NO_X, and PM Project Costs Included?	Yes	Yes
Hg and HAPs MACT Project Costs Included?	Yes	Yes
Incremental NO_X Project Costs Included?	No	Yes
CCR Project Costs Included?	No	Yes
316(b) Project Costs Included?	No	Yes
Total Incremental Investment Cost Included	[redacted]	[redacted]

Costs for Recovery of Remaining Depreciation Expense

The proof-of-concept coal utilization sensitivity analysis encumbered betterment natural gas resources with the costs for recovery of any remaining existing depreciation expense, but did not account for any incremental cost for recovery of depreciation expense related to the incremental coal resource investments. Given costs for recovery of existing depreciation expenses are applicable regardless of whether the coal resource is kept in service or if the coal resource is decommissioned, these costs were removed from the System Optimizer model for the Coal Replacement Study. To better reflect the cost tradeoffs considered by the System Optimizer model in determining whether a coal resource requiring incremental investment should be displaced by replacement resources, only costs for recovery of remaining depreciation of the incremental investments were used in the Coal Replacement Study.

Confidential Figure 1 shows how annual coal investment costs for SO_2, NO_X, PM, Hg and non-Hg HAPs, CCR, and 316(b) projects compare with costs for the recovery of remaining depreciation expense from incremental investments as implemented in the System Optimizer model. The up-front capital for coal investment costs are converted to a real levelized cost consistent with the treatment of all capital costs in the 2011 IRP and consistent with the System Optimizer model data requirements. The nominal net present value (NPV) of these real levelized investment costs in any given year represents the cost of capital from that year through the end of the planning period in 2030 if investments are made and the coal resource is not decommissioned. The nominal NPV of costs for the recovery of any remaining depreciation expense in any given year represents the recovery of costs for incremental investments made prior to that year. These costs represent the costs that would be incurred if future incremental investments are not made and coal resources are decommissioned in that year. The difference between these two streams of costs at any given point in time represent the capital cost tradeoff between making incremental coal investments and foregoing those investments in favor of decommissioning.

For example, as shown in Confidential Figure 1, the NPV of the remaining real levelized cost to make incremental coal investments across the fleet is approximately [redacted] in 2020. This is nearly [redacted] higher than the [redacted] of cost that would be incurred for recovery of remaining incremental depreciation from coal investments made in prior years if coal resources were decommissioned. This cost differential isolates the tradeoff between on-going incremental investments and costs for recovery of remaining incremental depreciation expense at any given point in time. The System Optimizer model considers this cost differential along with other cost tradeoffs related to on-going fixed costs of coal resources and replacement resources, decommissioning costs, replacement resource capital costs, and net variable cost differences between coal resources and replacement resource alternatives.

Confidential Figure 1 – Annual Incremental Coal Resource Investment Cost vs. Annual Cost for Recovery of Remaining Incremental Depreciation Expense

Figure Redacted.

Market Price and CO_2 Cost Assumptions

Overview

Natural gas prices and CO_2 costs are important to the evaluation of the economic tradeoff between coal resources and replacement resource alternatives. The assumed price for natural gas directly affects the cost of fuel for natural gas-fired replacement resources while also influencing the market price for power. As such, natural gas prices are critical to setting the cost for natural gas replacement resource alternatives and in influencing the economic benefits of both coal resources and replacement resource alternatives owing to its influence in the power market. Similarly, because of the relatively high carbon content in coal, higher CO_2 costs disproportionately affect the cost of emissions at coal facilities while also directly influencing the market price for power. Just as natural gas prices influence the economic tradeoffs between coal resources and potential replacement resource alternatives, the cost ascribed to CO_2 affects the cost of emissions for coal resources, and to a lesser extent, for natural gas replacement resources. The assumed level for CO_2 costs also influences the economic benefits for both coal and all replacement resource alternatives given its potential to influence prices in the power market.

The coal utilization sensitivity analysis in the 2011 IRP was performed among different sets of assumptions for future market prices as driven by the price for natural gas and for future CO_2 costs. The analysis paired medium natural gas prices with medium CO_2 costs, high CO_2 costs, and a hard CO_2 cap for PacifiCorp's system. The analysis also paired low natural gas prices with medium CO_2 costs and high CO_2 costs. Given the outlook for market prices and the prospects for future CO_2 regulations have evolved since these assumptions were developed for the 2011 IRP, the scenarios used in the Coal Replacement Study were updated to reflect a reasonable high and low range around the most current base case projection.

Base Case

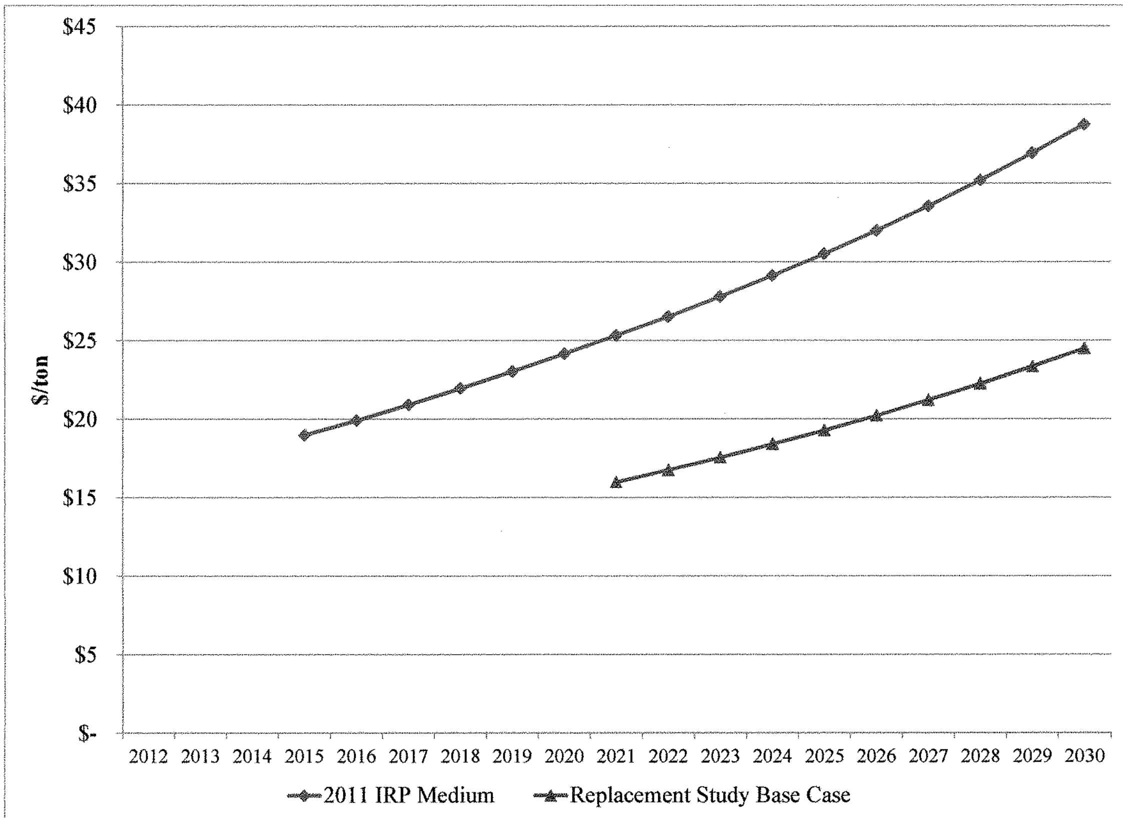
The June 30, 2011 official forward price curve (FPC) was used to set market prices for the base case. The front 72 months of the official FPC is derived from market forwards as of market close on a given quote date, which for purposes of the Coal Replacement Study, was June 30, 2011. Beyond the front 72 months of the FPC, a fundamentals-based forecast of market prices is developed using an hourly production cost dispatch model of the western interconnect consistent with current third party forecasts of long-term natural gas prices. These forecasts are blended with the forward market prices from months 73 through 84 and directly used in the FPC from months 85 and beyond.

One of the many inputs used to develop the fundamentals-based price forecast is an assumption for the cost of CO_2. The CO_2 cost assumptions applied in the base case are the same as those used to develop the June 30, 2011 FPC, which has CO_2 costs beginning in 2021 at \$16.00/ton growing to \$24.49/ton by 2030. The CO_2 cost and timing used in the June 30, 2011 FPC are consistent with current assumptions used by a variety of third party forecast services, which in aggregate, are expecting policy initiatives that might impute a cost on CO_2 emissions to become effective later than previously forecasted. Table 2 summarizes how the base case natural gas prices used for the Coal Replacement Study compare to medium gas prices in the 2011 IRP. Figure 2 shows differences in CO_2 cost assumptions.

Table 2 – Comparison of Base Case Natural Gas to 2011 IRP Medium Natural Gas Prices (Henry Hub \$/MMBtu)

	2015	2020	2025	2030
2011 IRP Medium	\$7.43	\$8.09	\$9.58	\$10.04
Coal Replacement Study Base Case	\$5.70	\$7.23	\$8.39	\$9.98

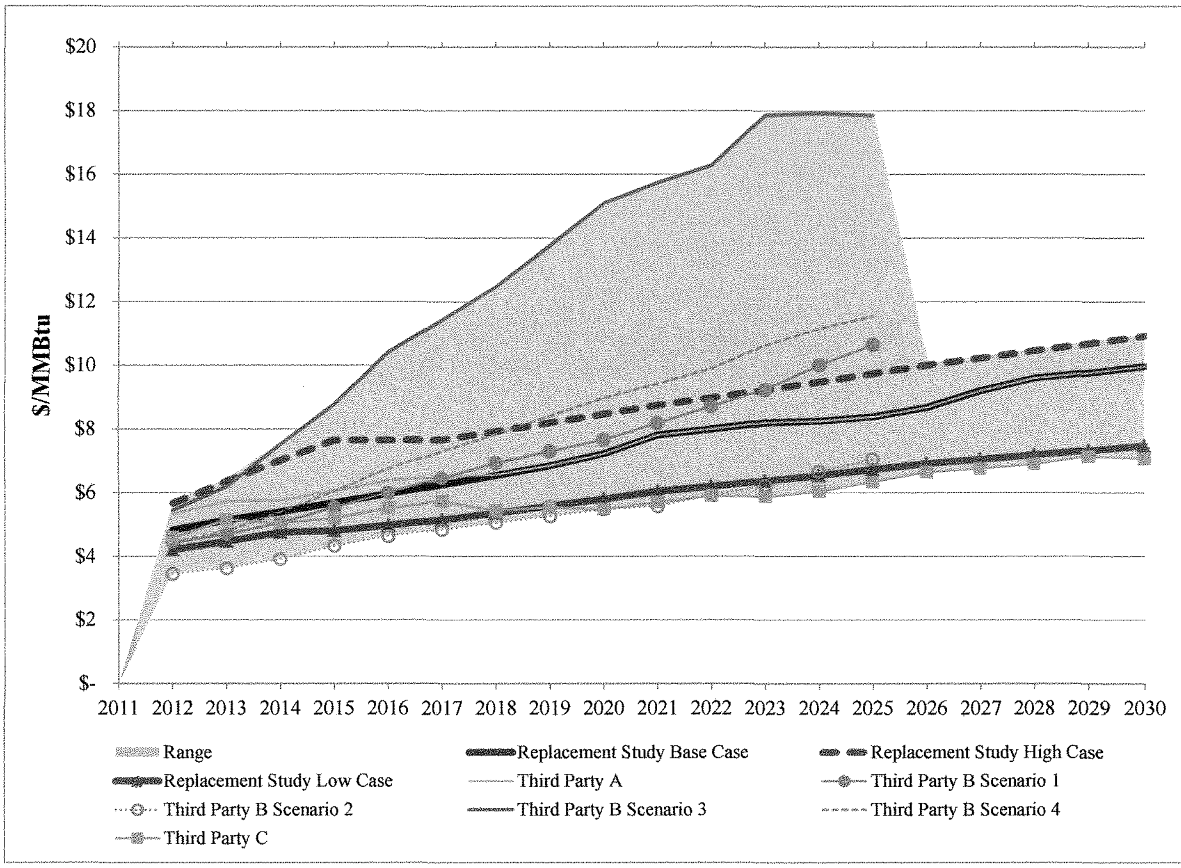
Figure 2 – Comparison of Base Case CO_2 Costs to 2011 IRP Medium CO_2 Costs



Natural Gas Price Scenarios

High and low natural gas price scenarios were developed by comparing current third party natural gas price forecasts to those in the base case and to those used in the 2011 IRP. Six different price projections from three different forecast services were included in this review. Figure 3 shows the natural gas price forecasts selected for the Coal Replacement Study alongside these third party price forecasts. The low natural gas prices used in the Coal Replacement Study are reasonably close to the low end of the range among current third party projections. The high natural gas prices used in the Coal Replacement Study align well with the highest of the third party price forecast through about 2014 before leveling off at an average 15% premium to the base case. The high case used for the Coal Replacement Study was not aligned with the highest third party price forecast over the long-term given this projection is an outlier relative to the others and is not a plausible representation of where the gas market might settle over the long-term on a sustained basis.

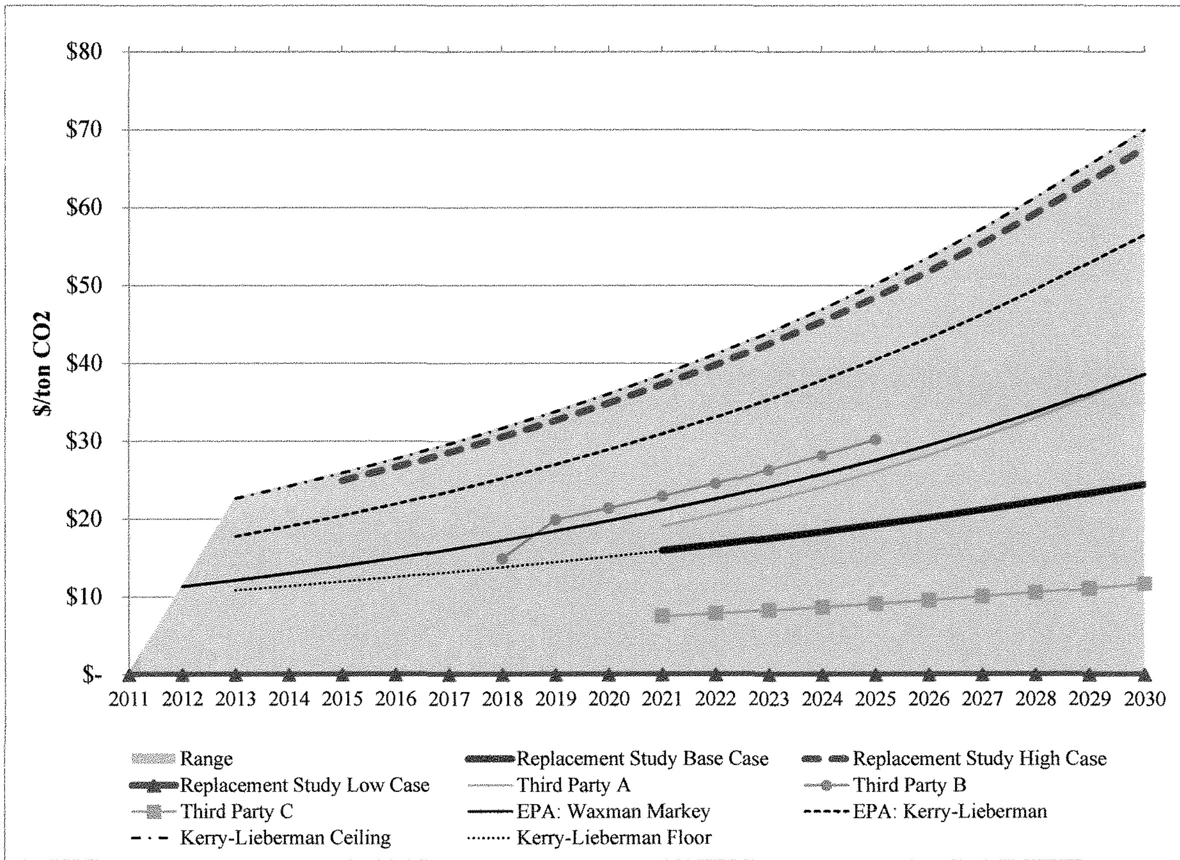
Figure 3 – Comparison of High and Low Case Natural Gas Prices to Third Party Projections (Henry Hub)



CO_2 Cost Scenarios

High and low CO_2 cost scenarios were developed by reviewing external forecasts of CO_2 costs alongside forecasts developed by EPA in their evaluation of past legislative proposals to limit greenhouse gas emissions. Three different price projections from third party forecast services along with EPA's projections for prices under the Waxman-Markey Bill and Kerry-Lieberman proposal were included in this review. Figure 4 shows the CO_2 costs selected for the Coal Replacement Study alongside these external projections. For the low case, it was assumed there would be no policy developments that would impute a cost on CO_2 emissions in the power sector within the 20-year study period. This assumption is consistent with a third party forecaster that has indicated there is real potential for a zero CO_2 cost scenario. The high CO_2 cost forecast adopted for the Coal Replacement Study is higher and starts sooner than any of the current projections from third party sources, but remains consistent with an upper limit that would have been established under the American Power Act of 2010 as proposed by Senators Kerry and Lieberman in May 2010.

Figure 4 – Comparison of High and Low Case CO_2 Costs to External Projections



Coal Replacement Study Results

Among all three scenarios evaluated in the Coal Replacement Study, none of the PacifiCorp coal resources were displaced by replacement resource alternatives before the end of the 20-year planning period or before the end of the currently approved depreciable life of each resource. In each of these scenarios, existing coal resources were assigned incremental investment costs consistent with the most current emissions control plan, plus the incremental SCR costs across the Company's generation units discussed above and in Confidential Appendix A. The analysis also incorporated cost estimates to address expected CCR regulations and upgrades to water intake structures. These findings support the basic conclusions drawn from the 2011 IRP coal utilization sensitivity analysis and show that PacifiCorp's coal fleet, with planned incremental investments, will continue to provide reliable and least cost electric service to customers. Moreover, the Coal Replacement Study shows that planned coal investments are cost effective among a range of future market price and CO_2 cost outcomes.

Appendix B shows the least cost resource portfolios for each of the three scenarios considered in the Coal Replacement Study. Appendix C provides unit level annual generation detail for each of the three scenarios studied.

Confidential Appendix A – Incremental Coal Investment Costs

Table A1 – Annual Coal Investment Costs used in the Coal Replacement Study

Redacted table.

Appendix B – Resource Portfolios

Table B1 – Base Case Coal Replacement Study Resource Portfolio

	BASE CASE	Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	Coal Ret_WY - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	716	-	-	-	716
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT G 1x1	-	-	-	-	-	-	-	-	-	388	-	-	-	-	-	-	388	-	-	358	388	1,134
	CCCT H 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	-	-	-	475	-	950
	SCCT Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118	-	-	118
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	0.8	0.8	-	-	0.8	0.8	0.8	-	-	-	-	-	-	2	4
	DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, GO-DLC-IRR	-	-	-	-	-	-	-	8	-	-	-	-	-	1	-	1	-	-	-	-	8	10
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	34	38	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	85	85
	DSM, Class 1, UT-DLC-IRR	-	-	-	-	-	-	-	11	-	-	-	-	-	1	-	2	-	-	-	-	11	14
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	5
	DSM, Class 1 Total	6	5	-	-	-	-	-	53	123	-	-	-	-	7	-	3	-	-	-	-	187	196
	DSM, Class 2, GO	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	43
	DSM, Class 2, UT	41	48	41	43	44	47	50	55	71	58	67	89	86	91	78	92	64	75	89	66	499	1,296
	DSM, Class 2, WY	3	4	4	4	5	6	6	7	7	8	9	10	11	14	15	19	20	24	31	31	53	236
	DSM, Class 2 Total	44	53	46	48	50	55	59	64	80	67	78	101	100	108	96	114	87	102	123	100	566	1,575
	Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	0.27	-	24	40
	FOT Mead Q3	-	168	264	189	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah Q3	200	17	83	-	187	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	24
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	0.3	0.3	-	-	0.3	0.3	0.3	-	-	-	-	-	-	1	2
	DSM, Class 1, WW-DLC-IRR	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, WM-DLC-IRR	-	-	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, YA-DLC-IRR	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	63	6	-	-	-	-	-	-	-	-	-	-	-	70	70
	DSM, Class 2, WA	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	91
	DSM, Class 2, WM	51	51	54	59	60	60	59	52	52	52	52	52	52	53	53	52	44	37	37	36	550	1,018
	DSM, Class 2, YA	6	6	6	6	6	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	64	141
	DSM, Class 2 Total	61	62	65	70	71	70	70	63	63	64	65	66	66	67	67	64	55	47	47	47	659	1,250
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	1.81	-	-	-	-	16	26
	FOT COB Q3	-	400	400	400	392	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	330	336
	FOT MidColumbia Q3	-	400	400	400	400	383	400	400	400	400	254	360	400	400	308	400	250	400	400	400	358	358
	FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT West Main Q3	-	50	50	50	50	-	28	50	50	41	-	-	38	50	-	50	-	1	50	47	37	30
	Annual Additions, Long Term Resources	132	152	130	756	134	750	138	563	583	729	355	378	377	393	747	291	634	970	393	984		
	Annual Additions, Short Term Resources	200	1,307	1,558	1,339	1,428	1,024	1,070	1,092	1,092	1,083	895	1,001	1,080	1,092	950	1,092	892	1,043	1,092	1,089		
	Total Annual Additions	332	1,459	1,688	2,094	1,562	1,774	1,208	1,654	1,675	1,811	1,251	1,379	1,457	1,485	1,697	1,382	1,526	2,013	1,485	2,073		

1/ Front office transaction amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average.

Table B2 – High Case Coal Replacement Study Resource Portfolio

	HIGH CASE	Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	Coal Ret_WY - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	716	-	-	-	716
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT G 1x1	-	-	-	-	-	-	-	-	-	388	-	-	-	-	-	-	-	-	-	388	388	776
	CCCT H 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	475	-	-	475	-	1,425
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, GO-DLC-IRR	-	-	-	-	8	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	18	54	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	85	85
	DSM, Class 1, UT-DLC-IRR	-	-	-	-	11	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	2	-	-	5
	DSM, Class 1 Total	6	5	-	-	20	-	-	18	138	-	-	-	-	5	-	3	-	-	2	-	187	196
	DSM, Class 2, GO	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	44
	DSM, Class 2, UT	45	49	43	46	48	52	53	55	61	60	62	90	86	91	76	92	73	89	89	73	510	1,331
	DSM, Class 2, WY	3	4	4	5	5	6	7	7	7	8	9	10	12	14	15	20	21	25	31	31	56	243
	DSM, Class 2 Total	48	53	48	52	54	60	62	64	70	69	74	102	101	108	94	115	97	117	123	107	581	1,618
	Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	24	47
	FOT Mead Q3	-	168	264	181	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71	36
	FOT Utah Q3	200	14	78	-	157	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	DSM, Class 1, WW-DLC-IRR	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	6
	DSM, Class 1, WM-DLC-IRR	-	-	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, YA-DLC-IRR	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	63	-	-	-	-	-	6	-	-	-	-	-	-	63	70
	DSM, Class 2, WA	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
	DSM, Class 2, WM	51	51	54	59	60	60	59	52	52	52	52	52	53	53	53	53	45	37	37	36	551	1,021
	DSM, Class 2, YA	6	6	6	6	7	7	7	7	7	7	8	9	9	9	9	7	6	7	7	7	66	143
	DSM, Class 2 Total	61	62	65	70	72	71	71	63	63	64	65	66	67	67	67	65	55	47	47	47	663	1,257
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	1.81	1.81	-	16	32
	FOT COB Q3	-	400	400	400	392	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	330	336
	FOT MidColumbia Q3	-	400	400	400	400	299	342	400	400	390	206	313	400	400	309	400	163	301	400	400	343	336
	FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT West Main Q3	-	50	50	50	50	50	50	50	50	50	50	50	42	50	-	50	-	-	50	15	45	38
	Annual Additions, Long Term Resources	136	153	133	760	159	755	142	527	582	731	351	378	377	396	746	292	736	989	282	1,022		
	Annual Additions, Short Term Resources	200	1,303	1,553	1,331	1,398	990	1,033	1,092	1,092	1,081	898	1,004	1,083	1,092	951	1,092	805	943	1,092	1,057		
	Total Annual Additions	336	1,456	1,686	2,091	1,556	1,746	1,176	1,618	1,673	1,812	1,249	1,382	1,460	1,488	1,697	1,384	1,541	1,932	1,374	2,079		

1/ Front office transaction amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average.

Table B3 – Low Case Coal Replacement Study Resource Portfolio

	LOW CASE	Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	Coal Ret_WY - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	716	-	-	-	716
	CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
	CCCT G 1x1	-	-	-	-	-	388	-	358	-	388	-	-	-	-	-	-	-	-	-	-	1,134	1,134
	CCCT H 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	-	-	-	475	-	950
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	186	-	-	186
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	-	0.8	-	0.8	-	-	-	2
	DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, GO-DLC-IRR	-	-	-	-	8	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	8	10
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	71	-	-	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	33	-	-	-	-	-	35	17	-	-	-	-	-	-	33	85
	DSM, Class 1, UT-DLC-IRR	-	-	-	-	11	-	-	-	-	-	-	-	1	-	-	2	-	-	-	-	11	14
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	5
	DSM, Class 1 Total	6	5	-	-	20	-	104	-	-	-	-	-	38	17	-	8	-	-	-	-	135	196
	DSM, Class 2, GO	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	42
	DSM, Class 2, UT	40	44	36	38	39	47	49	45	48	54	56	60	58	86	73	91	77	88	76	61	439	1,165
	DSM, Class 2, WY	1	1	-	4	5	5	6	6	6	7	8	9	11	13	14	19	20	24	29	28	40	213
	DSM, Class 2 Total	41	45	37	43	45	54	56	53	56	63	66	70	72	102	90	113	100	114	108	92	493	1,420
	Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	0.27	0.27	0.27	0.27	2.64	2.64	2.64	0.27	2.64	0.27	0.27	0.27	0.27	17	29
	FOT Mead Q3	-	168	264	207	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	42
	FOT Utah Q3	200	25	97	-	119	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	22
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																							
	CCCT G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	-	388
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	IC Aero YA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	307	-	-	-	-	307
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	0.3	-	0.3	-	-	-	1
	DSM, Class 1, WW-DLC-IRR	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	6
	DSM, Class 1, WM-DLC-IRR	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, YA-DLC-IRR	-	-	-	-	1	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	22	-	42	-	-	-	-	-	-	6	-	-	-	-	-	-	63	70
	DSM, Class 2, WA	4	4	4	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	3	3	44	86
	DSM, Class 2, WM	50	51	54	59	60	60	59	51	52	52	52	52	52	52	52	52	44	37	36	36	548	1,013
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	7	7	8	9	9	9	9	7	6	7	6	7	61	138
	DSM, Class 2 Total	60	61	65	69	71	70	70	61	62	63	64	65	65	66	66	64	54	47	46	46	653	1,237
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	-	0.97	-	-	14	20
	FOT COB Q3	-	400	400	400	391	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	330	336
	FOT MidColumbia Q3	-	400	400	400	400	400	400	283	400	400	253	385	400	400	313	400	311	400	400	400	348	357
	FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT West Main Q3	-	50	50	50	50	50	50	-	34	30	-	-	50	50	-	50	-	50	50	26	36	32
	Annual Additions, Long Term Resources	128	144	121	751	170	540	282	787	425	720	338	344	383	401	737	295	566	985	446	1,006		
	Annual Additions, Short Term Resources	200	1,315	1,572	1,357	1,360	1,191	1,092	924	1,075	1,071	895	1,027	1,092	1,092	955	1,092	952	1,092	1,092	1,068		
	Total Annual Additions	328	1,459	1,693	2,108	1,530	1,730	1,374	1,711	1,500	1,791	1,233	1,371	1,475	1,493	1,692	1,387	1,518	2,076	1,537	2,074		

1/ Front office transaction amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average.

Appendix C – Existing Coal Unit Annual Generation

Table C1 – Base Case Coal Resource Generation

	Base Case Annual Generation (GWh)																			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon1	496	479	469	510	510	482	482	514	516	518	End of Depreciable Life									
Carbon2	780	743	740	787	787	784	747	794	803	804	End of Depreciable Life									
Cholla	2,678	2,899	2,827	2,899	2,904	2,956	3,060	3,107	3,107	3,107	3,099	3,086	3,078	3,068	2,506	2,433	2,638	2,657	2,629	2,542
Colstrip3	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Colstrip4	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508
Craig1	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Craig2	679	679	694	694	693	693	693	693	693	693	693	693	693	693	693	693	693	693	693	693
Hayden1	309	316	316	321	320	321	338	344	344	344	344	344	344	342	339	339	344	344	342	339
Hayden2	258	262	261	261	252	263	266	268	268	268	287	287	287	287	287	287	287	287	287	287
Hunter1	2,840	3,257	3,267	3,301	3,334	3,339	3,342	3,342	3,342	3,342	3,319	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Hunter2	1,749	1,985	2,049	2,069	2,102	2,106	2,116	2,116	2,116	2,116	2,099	2,114	2,116	2,115	2,114	2,116	2,116	2,116	2,116	2,116
Hunter3	3,067	3,521	3,517	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,547	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561
Huntington1	3,672	3,672	3,672	3,672	3,672	3,672	3,651	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672
Huntington2	3,471	3,471	3,471	3,471	3,471	3,610	3,556	3,607	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610
JBridger1	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,723	2,723	2,723	2,723	2,711	2,712	2,699	2,700	2,703	2,718	2,723	2,712	2,723
JBridger2	2,636	2,640	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,623	2,623	2,604	2,609	2,637	2,656	2,658	2,649	2,657
JBridger3	2,490	2,554	2,579	2,615	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,676	2,678	2,665	2,665	2,665	2,687	2,687	2,687	2,701
JBridger4	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,522	2,522	2,511	2,511	2,511	2,524	2,537	2,537	2,549
Johnston1	763	752	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	End of Depreciable Life		
Johnston2	823	822	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832	End of Depreciable Life		
Johnston3	1,179	1,172	1,185	1,492	1,849	1,376	1,432	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	End of Depreciable Life		
Johnston4	2,286	2,286	2,198	2,253	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	End of Depreciable Life		
Naughton1*	1,019	1,169	1,129	1,139	1,157	1,157	1,162	1,235	1,243	1,246	1,241	1,243	1,243	1,237	1,240	1,227	1,235	1,235	1,235	End of Life
Naughton2*	1,313	1,434	1,434	1,462	1,486	1,486	1,517	1,602	1,611	1,611	1,592	1,592	1,591	1,586	1,587	1,581	1,589	1,599	1,586	End of Life
Naughton3*	1,997	2,278	2,257	2,262	2,368	2,298	2,395	2,426	2,444	2,444	2,432	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	End of Life
Wyodak1	2,249	2,249	2,249	2,027	1,665	2,223	2,231	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249
Grand Total	**43,768**	**45,655**	**45,666**	**46,148**	**46,498**	**46,695**	**46,917**	**47,820**	**47,871**	**47,876**	**46,475**	**46,387**	**46,383**	**46,302**	**45,747**	**45,688**	**45,983**	**40,213**	**40,151**	**34,831**

*As with the Carbon and Dave Johnston units, Naughton reaches the end of its currently expected depreciable life within the planning period (at the end of 2029)

Table C2 – High Case Coal Resource Generation

	High Case Annual Generation (GWh)																			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon1	523	518	520	523	516	472	288	265	215	33	End of Depreciable Life									
Carbon2	807	804	807	807	804	795	752	715	728	638	End of Depreciable Life									
Cholla	3,146	3,146	3,146	3,146	2,921	2,916	2,903	2,730	2,755	2,663	2,716	2,576	2,458	2,282	1,561	1,542	1,280	1,206	1,099	857
Colstrip3	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	584
Colstrip4	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	497
Craig1	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Craig2	679	679	694	694	694	694	692	692	692	691	691	688	688	688	688	687	687	687	682	675
Hayden1	348	348	348	348	321	321	318	320	311	317	317	304	299	272	248	237	215	202	198	179
Hayden2	271	271	271	271	259	258	251	251	251	251	269	269	269	261	258	240	218	223	209	197
Hunter1	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,306	3,342	3,342	3,342	3,168	2,991	2,357	2,659	2,387	1,751
Hunter2	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,091	2,108	2,108	2,109	1,970	1,851	1,280	1,415	1,066	693
Hunter3	3,421	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,546	3,561	3,561	3,561	3,452	3,323	2,919	3,079	2,891	2,123
Huntington1	3,672	3,672	3,672	3,672	3,672	3,672	3,667	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,665	3,628	3,642	3,581	3,238
Huntington2	3,471	3,471	3,471	3,471	3,471	3,610	3,595	3,610	3,610	3,603	3,610	3,610	3,610	3,610	3,610	3,582	3,511	3,541	3,371	2,907
JBridger1	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,723	2,723	2,723	2,723	2,680	2,627	2,554	2,060	1,682	981	1,087	967	573
JBridger2	2,640	2,640	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,600	2,548	2,413	1,753	1,347	466	594	555	391
JBridger3	2,533	2,553	2,578	2,613	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,503	2,262	1,870	1,021	749	175	213	223	198
JBridger4	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,468	2,446	2,283	1,545	1,158	229	348	425	213
Johnston1	763	752	840	840	840	840	840	840	840	840	840	840	840	840	840	840	835	End of Depreciable Life		
Johnston2	823	822	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832	End of Depreciable Life		
Johnston3	1,179	1,172	1,185	1,492	1,848	1,853	1,856	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,854	1,763	End of Depreciable Life		
Johnston4	2,286	2,286	2,198	2,253	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	End of Depreciable Life		
Naughton1*	1,256	1,256	1,251	1,252	1,241	1,236	1,220	1,225	1,225	1,223	1,224	1,221	1,167	1,092	756	480	147	151	112	End of Life
Naughton2*	1,596	1,618	1,620	1,626	1,594	1,587	1,539	1,540	1,530	1,516	1,514	1,289	1,030	829	399	378	88	93	107	End of Life
Naughton3*	2,444	2,442	2,452	2,452	2,442	2,423	2,421	2,421	2,421	2,421	2,421	2,445	2,445	2,439	2,273	1,985	1,314	1,545	1,385	End of Life
Wyodak1	2,249	2,249	2,249	2,027	1,662	1,743	1,805	2,249	2,239	2,239	2,245	2,249	2,249	2,249	2,238	2,161	1,899	1,887	1,423	939
Grand Total	**46,579**	**46,734**	**46,836**	**47,019**	**46,833**	**46,968**	**46,695**	**47,001**	**46,962**	**46,579**	**45,913**	**45,195**	**44,392**	**43,135**	**38,280**	**35,660**	**28,901**	**24,362**	**22,469**	**16,702**

*As with the Carbon and Dave Johnston units, Naughton reaches the end of its currently expected depreciable life within the planning period (at the end of 2029)

Table C3 – Low Case Coal Resource Generation

	Low Case Annual Generation (GWh)																			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon1	523	520	520	523	523	523	523	523	523	523	End of Depreciable Life									
Carbon2	807	807	807	807	807	807	807	807	807	807	End of Depreciable Life									
Cholla	3,125	3,146	3,082	3,082	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146
Colstrip3	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Colstrip4	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508
Craig1	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Craig2	679	679	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694
Hayden1	348	339	341	341	348	348	348	348	348	348	348	348	348	348	348	348	348	348	348	348
Hayden2	271	271	271	271	271	271	271	271	271	271	291	291	291	291	291	291	291	291	291	291
Hunter1	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Hunter2	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116
Hunter3	3,421	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561
Huntington1	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672
Huntington2	3,471	3,471	3,471	3,471	3,471	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610
JBridger1	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723
JBridger2	2,640	2,640	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668
JBridger3	2,538	2,564	2,595	2,628	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,724	2,726	2,727	2,728	2,729	2,729	2,729
JBridger4	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562
Johnston1	763	752	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	End of Depreciable Life		
Johnston2	823	822	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832	End of Depreciable Life		
Johnston3	1,180	1,173	1,185	1,492	1,850	1,384	1,440	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	End of Depreciable Life		
Johnston4	2,286	2,286	2,198	2,253	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	End of Depreciable Life		
Naughton1*	1,251	1,256	1,236	1,236	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	End of Life
Naughton2*	1,591	1,565	1,553	1,607	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	End of Life
Naughton3*	2,439	2,452	2,452	2,442	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	End of Life
Wyodak1	2,249	2,249	2,249	2,027	1,675	2,226	2,234	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249
Grand Total	**46,581**	**46,699**	**46,699**	**46,918**	**47,185**	**47,408**	**47,473**	**47,970**	**47,970**	**47,970**	**46,660**	**46,660**	**46,660**	**46,656**	**46,657**	**46,659**	**46,660**	**44,387**	**44,551**	**39,031**

*As with the Carbon and Dave Johnston units, Naughton reaches the end of its currently expected depreciable life within the planning period (at the end of 2029)