PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

November 26, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

Re: LC 57 PacifiCorp's Reply Comments

Pursuant to the administrative law judge's ruling on November 8, 2013 modifying the schedule, PacifiCorp d/b/a Pacific Power submits for filing its Reply Comments on PacifiCorp's 2013 Integrated Resource Plan.

Please contact Gary Tawwater, Manager, Regulatory Affairs, at (503) 813-6805, for questions on this matter.

Sincerely,

William R. Griffith /GWT

William R. Griffith
Vice President, Regulation

Enclosures

cc: Service List – LC 57

CERTIFICATE OF SERVICE

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

<u>Oregon Docket LC 57</u>

Kacia Brockman (W)(C)
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
kacia.brockman@state.or.us

Philip H. Carver (W)
Oregon Department of Energy
625 Marion St. NE Ste 1
Salem, OR 97301
phil.carver@state.or.us

Renee M France (W)(C)
Oregon Department of Justice
1162 Court St NE
Salem, OR 97301-4096
Renee.m.france@doj.state.or.us

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 SW Broadway – Ste 400
Portland, OR 97205
dockets@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

Regulatory Dockets (W)
Idaho Power Company
PO Box 70
Boise, ID, 83707-0070
dockets@idahopower.com

Lisa D. Nordstrom (W)(C)
Idaho Power Company
PO Box 70
Boise, ID, 83707-0070
lnordstrom@idahopower.com

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

Fred Heutte (W)(C)
NW Energy Coalition
1205 SE Flavel
Portland, OR 97202
fred@nwenergy.org

Ralph Cavanagh (W)
Natural Resources Defense Council
111 Sutter St. Floor 20
San Francisco, CA 94104
rcavanagh@nrdc.org

Angus Duncan (W)(C)
Natural Resources Defense Council
2373 NW Johnson St
Portland, OR 97210
angusduncan@b-e-f.org

Mary Wiencke (W) (C)
Pacific Power
825 NE Multnomah St, Suite 1800
Portland, OR 97232-2149
Mary.wiencke@pacificorp.com

Patrick G Hager (W)
121 SW Salmon Street 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com;
Patrick.hager@pgn.com

Brian Kuehne (W)
Portland General Electric
121 SW Salmon Street 3WTCBR06
Portland, OR 97204
Brian.kuehne@pgn.com

Juliet Johnson (W)(C)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
Juliet.johnson@state.or.us

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

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

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

RNP Dockets (W)
Renewable Northwest Project
421 SW 6th Avenue, #1125
Portland, OR 97204-1629
dockets@rnp.org

Derek Nelson (W)(C)
Sierra Club Environmental Law
85 Second Street, 2nd Floor
San Francisco, CA 94105
derek.nelson@sierraclub.org

V. Denise Saunders (W)
Portland General Electric
121 SW Salmon Street 1WTC1301
Portland, OR 97204
Denise.Saunders@pgn.com

Megan Walseth Decker (W)(C)
Renewable Northwest Project
421 SW 6th Avenue, #1125
Portland, OR 97204-1629
megan@rnp.org

Lisa F. Rackner (W)(C)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
dockets@mcd-law.com

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

Travis Ritchie (W)(C)
Sierra Club Environmental Law
85 Second Street, 2nd Floor
San Francisco, CA 94105
Travis.ritchie@sierraclub.org

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

DATED: November 26, 2013

Carrie Meyer
Supervisor, Regulatory Operations

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 57

In the Matter of PACIFICORP, dba PACIFIC POWER 2013 Integrated Resource Plan	REPLY COMMENTS

1. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) filed its 2013 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on April 30, 2013, and a Wind Integration Study Technical Memo on June 3, 2013. The Company's IRP was prepared in accordance with the terms of Order No. 12-493, in which the Commission acknowledged the Company's 2011 IRP and revised Action Plan, with exceptions, as well as Order Nos. 07-002 and 07-047, in which the Commission adopted the Oregon IRP Guidelines. As part of its review, the Commission considers the extent to which the plan satisfies the procedural and substantive requirements of Oregon's IRP Guidelines and whether the plan is reasonable at the time of acknowledgement.

As part of the IRP acknowledgment schedule adopted by the administrative law judge for this proceeding, parties filed written comments and recommendations on August 22, 2013. Parties provided additional comments to the Commission at the October 28, 2013 special public meeting. Eight parties submitted written comments: Commission staff (Staff), Citizens' Utility Board of Oregon (CUB), Northwest Energy Coalition (NWEC), Renewable Northwest Project (RNP), Oregon Department of Energy (ODOE), Industrial Customers of Northwest Utilities (ICNU), Sierra Club, and Natural Resources Defense Council (NRDC).

Each of these parties also provided oral comments to the Commission at the October 28, 2013 special public meeting. In response to these comments, PacifiCorp submits these reply comments for consideration. Following the executive summary/recommendations section, the Company first replies to comments from the October 28, 2013 special public meeting, focusing on specific recommendations that were not addressed in the parties' written comments. The Company then replies to the written comments that were filed by the parties in August 2013. PacifiCorp's reply to the parties' written comments is organized by responding party.

In addition to providing comments to the Commission since the filing of the Company's 2013 IRP, the parties to this docket also participated in an extensive pre-filing process that included more than double the amount of public input meetings than previous years. These meetings were used to discuss and receive stakeholder input on a comprehensive set of planning topics, including the analysis of investments in coal-fired generating units. The pre-filing process for the 2013 IRP also included the following process and modeling improvements that were implemented since the Company's 2011 IRP:

- Expanded modeling framework that captured transmission expansion scenarios and coal unit investment alternatives within the IRP portfolio development process;
- Addition of Confidential Volume III, which includes detailed financial analysis for specific near-term coal unit investments supporting coal resource action items in the Action Plan;
- Expanded representation of demand side management (DSM) resources, increasing cost steps in supply curves from nine in the 2011 IRP to 27 in the 2013 IRP;

- Expanded analysis of renewable portfolio standard (RPS) compliance requirements that captures flexibility mechanisms, such as banking provisions specific to state RPS programs;
- Updated wind integration analyses benefiting from the involvement and expertise of an independent technical review committee; and
- Updated loss of load probability study (LOLP) that measures the impact of reserve sharing arrangements with the Northwest Power Pool.

2. EXECUTIVE SUMMARY AND RECOMMENDATIONS

The purpose of these reply comments is to respond to the comments and recommendations of Staff and the other parties made during the October 28, 2013 special public meeting and in written comments filed in August 2013. Parties' comments at the October special public meeting were primarily focused on coal unit environmental investments, environmental policy assumptions, and DSM resources. PacifiCorp addresses each of these topics in detail, while also responding to all of the parties' written comments. In these reply comments, PacifiCorp provides additional information, clarification of its positions, and specific recommendations for the Commission's consideration in its review of the Company's 2013 IRP.

PacifiCorp has met the Oregon IRP Guidelines and requests that the Commission acknowledge the 2013 IRP. In particular, PacifiCorp requests that the Commission acknowledge its 2013 IRP Action Plan, including the following items:

- Action Item 8a, pertaining to the natural gas conversion of Naughton 3;
- Action Item 8b, pertaining to the baghouse conversion and low NO_X burner (LNB) investments required at Hunter 1;

- Action Item 8c, pertaining to the selective catalytic reduction (SCR) investments required at Jim Bridger 3 and 4; and
- Action Item 9c, pertaining to the Sigurd to Red Butte 345 kilovolt transmission line.

3. OCTOBER 28, 2013 SPECIAL PUBLIC MEETING

Coal Resources

At the October 28, 2013 special public meeting Staff presented specific recommendations related to environmental investments in coal units as a requirement for acknowledgment of PacifiCorp's 2013 IRP. Specifically, Staff recommended that additional analysis be performed for certain coal units with potential for environmental compliance obligations by 2019. Staff also recommended that PacifiCorp produce an updated screening model to develop scenarios for flexible compliance alternatives assuming potential for negotiated outcomes with state air regulatory agencies and the U.S. Environmental Protection Agency (EPA) and commented that the System Optimizer model may not be the right tool when analyzing environmental investments for coal units. Finally, Staff recommended that transmission implications be evaluated in alternative compliance scenarios.

Other parties commented on Staff's coal resource recommendations. CUB stated that absent alternative regulatory proceedings, Oregon stakeholders have only the IRP process to evaluate coal unit investment alternatives before a prudence review in a general rate case. CUB stated that it had considered recommending an investigatory docket as a forum for Oregon stakeholder participation, but stated that Staff's recommendations to continue the current IRP process with additional coal unit analysis would be acceptable. NWEC and Sierra Club supported Staff's recommendation that the Company update its coal screening model as a means to improve transparency. Several parties commented that additional analysis should be performed with alternative assumptions for CO_2 prices consistent with a Presidential Memorandum addressing future regulation of greenhouse gases (GHGs) issued June 25, 2013.

Regional Haze Program

The Company understands and supports Staff's and other parties' desire to rigorously review major environmental compliance alternatives, particularly when near term decision-making must be made, and has been working with Staff to address its concerns about the analyses in the 2013 IRP. Given the significant uncertainty of the nature and design of any future regulations affecting coal-fueled resources, it is critical to differentiate between alternative compliance scenarios based upon known and reasonably foreseeable outcomes, and those scenarios based on parameters from hypothetical future obligations that are not known and measureable and lack a reasonable measure of certainty. Compliance with Regional Haze requirements is an example of the complexity of effectively assessing and complying with emerging environmental regulations. To provide context for the Company's response to specific recommendations and comments from the October 28 special public meeting, PacifiCorp first summarizes the Regional Haze program and EPA's actions on the Utah and Wyoming state implementation plans (SIPs).

The Regional Haze program is a visibility improvement program that was enacted and adopted into law in 1999 and revised in 2005. Although its long-term goal is to return Class I areas in the U.S. to natural visibility conditions by 2064, the Regional Haze program also contains stringent requirements at the front end. The states, through development of SIPs, and the U.S. Environmental Protection Agency (EPA) are tasked with administering the Regional Haze program under two primary compliance timeframes: (1) the initial Best

Available Retrofit Technology (BART) planning and compliance period originally[1] required BART controls to be in place by 2013; and (2) long-term planning periods that require resubmittal of updated SIPs, including long-term strategy controls on BART and other units to meet reasonable progress goals, every ten years beginning in 2018. Because the Regional Haze program by its nature will affect all emissions sources within a region and be implemented over many years, there will continue to be emerging compliance obligations set forth by the state and federal agencies responsible for administering the rules for several decades to come, and projects and visibility improvements deployed and achieved in the initial BART phase of the program are intended to be built upon over time to ultimately achieve the program's 2064 visibility goals.

On December 14, 2012, EPA published its final rule in the *Federal Register* partially approving and partially disapproving the Utah Regional Haze SIP. EPA disapproved the particulate matter (PM) and nitrogen oxide (NO_X) portions of the SIP, and approved the sulfur dioxide (SO_2) SIP by allowing the state to use the SO_2 Milestone and Backstop Trading program to satisfy BART requirements for SO_2. Although EPA disapproved the Utah Regional Haze SIP for NO_X and PM, the state of Utah maintains that it's Regional Haze SIP and the permits that are issued under that SIP are enforceable under state law and will become federally enforceable when EPA approves the SIP. The Hunter Unit 1 low NO_X burners (LNB) and baghouse retrofit are incorporated into the Utah Regional Haze SIP with a completion date in spring 2014 and must achieve a NO_X emission rate of 0.26 pounds per

[1] The Final Amendments to the Regional Haze Rule and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 Fed. Reg. 128; July 6, 2005) contemplated that states would complete state implementation plans and the EPA issue final approval during 2008, which in turn would require BART controls to be installed at eligible units within five years (2013). Because EPA has not yet finalized its approval of the states' SIPs, the five-year clock continues to get pushed out in time from a federal compliance perspective.

million Btu and a PM emission rate of 0.015 pounds per million Btu, respectively. Failure to comply with Utah's Regional Haze SIP would expose PacifiCorp to enforcement action including, but not limited to, penalties and corrective action. Enforcement actions may be initiated by the local permitting authority (Utah Division of Air Quality), EPA, or through citizen suits.[2] While the original intent of the Utah Regional Haze SIP was to have the Hunter Unit 1 LNB and baghouse retrofit projects placed in service by year-end 2013 to align with the BART planning period discussed above, PacifiCorp was able to reach agreement with the state of Utah to defer installation of those emissions controls until 2014 to align with an established major maintenance outage for that unit; effectively delaying installation and mitigating additional costs to customers due to an off-cycle outage to tie in the equipment.

The Utah Regional Haze SIP requirements regarding Hunter Unit 1 baghouse retrofit are also a fundamental component of Utah's approved SO_2 Milestone and Backstop Trading Program. Installation of the baghouse retrofit required in the Utah Regional Haze SIP will allow closure of the existing scrubber bypass when the baghouse equipment is placed in service. Closure of the existing scrubber bypass will allow the unit to comply with an SO_2 emission rate of 0.12 pounds per million Btu, which is the emissions limit established by the SO_2 Milestone and Backstop Trading Program.

As part of its disapproval of the PM and NO_X portion of Utah's Regional Haze SIP, EPA required PacifiCorp and Utah to complete new five-factor BART analyses for those pollutants. PacifiCorp submitted a five-factor NO_X analysis to the Utah Division of Air Quality in June 2012 and continues to work with the Utah Division of Air Quality to support the development of a five-factor analysis that will be acceptable to the EPA as a supplement

[2] See Attachment A, which contains the Technical Support Documentation for Utah's 2008 Regional Haze SIP dated December 20, 2010.

to Utah's Regional Haze SIP. While the state is revisiting it approach to five-factor analyses of the NO_X requirements for BART-eligible units in the state, there is little doubt that LNB will remain cost effective as part of the final BART analyses, even though the possibility exists that EPA's view could prevail and result in post-combustion NO_X controls, such as SCR or selective non-catalytic reduction (SNCR), being required as BART in addition to LNBs. In addition, PacifiCorp and the Utah Department of Environmental Quality appealed the EPA's determination to partially disapprove Utah's Regional Haze SIP for PM and NO_X. PacifiCorp also intervened in support of the EPA's decision to approve the Regional Haze SO_2 Milestone and Backstop Trading Program.

On May 28, 2013, EPA issued a revised proposal regarding the Wyoming Regional Haze SIP. The revised proposal was published in the *Federal Register* on June 10, 2013. EPA proposed to approve and disapprove specific portions of the Wyoming Regional Haze SIP. Regarding the disapproved portions that impact PacifiCorp, EPA proposed a federal implementation plan (FIP) that would require the installation of SCR on Naughton 1 and 2 and Dave Johnston 3. EPA's proposal also requires the installation of SNCR on Dave Johnston 4 and Wyodak, and the installation of LNB on Dave Johnston 1 and 2. EPA proposed to accept Wyoming's plan requiring the installation of SCR on Jim Bridger 1 through 4 and a baghouse and SCR on Naughton 3. PacifiCorp filed public comments August 26, 2013, and EPA is currently obligated to take final action on the revised proposed plan by January 10, 2014, after having been recently granted an extension by the court. The process currently underway in Wyoming does not influence the compliance deadlines for those units addressed in PacifiCorp's 2013 IRP Action Plan.

In parallel to administration of the Regional Haze rules, state agencies and EPA must also ensure compliance with other environmental regulations including the recently enacted Mercury and Air Toxics Standards (MATS), and emerging regulations for coal combustion residuals (CCR) handling and storage, Clean Water Act §316(b) cooling water intake rules, and effluent limitation guidelines (ELG). The Company must therefore assess not only currently known obligations, but must also assess reasonably foreseeable compliance obligations in its analyses.

<u>2013 IRP Coal Resource Action Items</u>

In response to Staff's recommendations, PacifiCorp first addresses the applicability of these recommendations to specific coal unit investment action items in the 2013 IRP Action Plan. PacifiCorp included specific coal unit investment action items, focusing on the near-term, consistent with Oregon's IRP Guidelines and previous Commission decisions.[3] Each of the coal investment action items in the Action Plan are supported by financial analysis summarized within Confidential Volume III of the 2013 IRP. Specifically, these action items address investments at four coal units:

- Natural gas conversion of Naughton 3 (Action Item 8a)
- Installation of a baghouse conversion and LNB at Hunter 1 (Action Item 8b)
- Installation of SCR at Jim Bridger 3 and 4 (Action Item 8c)

In its recommendations, Staff did not identify a need for additional analysis to support the Naughton 3 natural gas conversion. Moreover, at a September 24, 2013 technical workshop in which PacifiCorp discussed the coal resource action items in the 2013 IRP

[3] See Oregon IRP Guideline 4m which requires "an action plan with resource activities the utility intends to undertake over the next two to four years". In the Commission's 2011 IRP Order (Docket No. LC-52, Order No. 12082), the Commission chose not to acknowledge action item 1, stating: "We will not acknowledge actions that are open-ended and too far in the future to be meaningful."

Action Plan, no party raised issues with the Naughton 3 action item. Similarly, Staff did not identify a need for additional analysis to support the SCR investments at Jim Bridger 3 and 4 in its October 28, 2013 recommendations.[4] Staff recommended that additional analysis be performed for environmental investments required at Hunter 1.

With respect to Hunter Unit 1, the Company is working with Staff to identify what, if any, additional analysis is necessary. The Utah Regional Haze SIP requires the installation of LNB and a baghouse retrofit at Hunter 1 by 2014. The enforceability of those requirements is discussed above. The Company has also discussed with parties the perceived flexibility afforded to the baghouse retrofit schedule via its association with meeting Utah's approved SO_2 Milestones and Backstop Trading Program. Ignoring the enforceable BART requirements of the PM portion of the Utah Regional Haze SIP for the sake of discussion, the Company offers a very similar argument regarding the state of Utah's underlying assumptions regarding their development of the SO_2 Milestone and Backstop Trading Program. The Regional Haze Rules require that an alternative program designed to replace source-specific BART controls must achieve greater reasonable progress than would be achieved by BART. In its proposed approval of Utah's alternative SO_2 program, EPA concludes:

> The State's better-than-BART demonstration provides numerous reasons why the SO_2 backstop trading program is better than BART…. The baseline emission projections and assumed reductions due to the assumption of BART-level emission rates on all sources subject-to-BART are all based on actual emissions, using 2006 as the baseline[.]

[4] Staff did not list Jim Bridger 3 and 4 in its list of units with potential requirements by 2019 for further review in this IRP docket. Subsequently, Staff submitted a data request on November 22, asking the Company to perform an alternative Hypothetical Compliance analysis on Jim Bridger 3 and 4. PacifiCorp has agreed to complete Staff's request for this analysis. Other parties raised concerns with the analysis supporting SCR investments at Jim Bridger 3 and 4 in the written comments filed with the Commission in August 2013. PacifiCorp addresses these concerns, as applicable, in its reply to the parties' opening comments herein.

In developing its final approval action on Utah's SO_2 Milestone and Backstop Trading Program, EPA acknowledges that Utah applied appropriate BART-level emission rates on all sources subject to BART, including Hunter 1. The BART-level SO_2 emissions rate for Hunter 1 captured in the program relies upon the baghouse retrofit being placed in service and the unit achieving the 0.12 pounds per million Btu SO_2 emission rate discussed earlier. As for the specific timing referenced in the SO_2 Milestones and Backstop Trading Program planning documentation, all references to BART-level emissions reductions for the Company's Utah units require compliance before the program's 2018 milestone; a schedule which is supported by the Utah Regional Haze SIP requirements for installation of baghouse retrofits (and their contributions to achieving BART-level SO_2 emissions reductions) on the Company's BART-eligible units during the BART planning period ending in 2013 (with the exception of Hunter Unit 1, as discussed above).

Installation of the Hunter Unit 1 baghouse will also allow the unit to comply with the mercury component of MATS by April 16, 2015. While the MATS rule allows for single-year extensions to be requested, up to two years in aggregate, if transmission reliability issues cannot be overcome or procurement and installation of the required MATS compliance equipment cannot be accomplished within the established 2015 compliance deadline, Hunter Unit 1, however, is not faced with those extenuating circumstances. Requesting such an extension, without meeting the underlying exclusionary exceptions is not supportable.

As summarized below, the Company has rigorously reviewed compliance alternatives to investments in LNB and a baghouse retrofit at Hunter Unit 1, while concurrently assessing costs associated with reasonably foreseeable potential future compliance obligations, including various timeframes for installation of post-combustion SCR technology. While parties have indicated that more analysis is required, no party has identified why the specific analyses the Company has completed do not support Action Item 8b in the 2013 IRP Action Plan, despite having nearly seven months to analyze the Company's 2013 IRP.

PacifiCorp included in Confidential Volume III the results of its financial analysis supporting the Hunter 1 action item in the 2013 IRP Action Plan. The Confidential Volume III analysis includes base case and scenario results as developed at the time PacifiCorp completed an appropriations request (APR) for the baghouse and LNB investments.[5] In evaluating environmental investment alternatives, the APR analysis considers prospective future environmental investment costs, including future costs for an SCR, future costs for CCR projects and cooling water intake structures, and costs for CO_2 emissions implemented among five different scenarios. This analysis shows the baghouse and LNB investments are the lowest cost compliance alternative among a range of natural gas price and CO_2 price scenarios. Confidential Volume III further includes an updated base case analysis and an additional sensitivity analysis that accelerates a hypothetical future SCR requirement to 2018.[6] Consistent with the APR analysis, both of these studies show the baghouse and LNB investments are the lowest cost compliance alternative. In response to parties' recommendation to give more careful consideration to high CO_2 price scenarios, PacifiCorp notes that the Confidential Volume III Hunter 1 financial analysis shows that the baghouse and LNB investments are the lowest cost alternative when high CO_2 prices (beginning 2018) are assumed.

[5] While there was no approval proceeding in Utah for the Hunter 1 investments, the analysis used to support the APR was performed using the same methods and with the same rigor as was done for the analysis filed in Wyoming and Utah for investments at Naughton 3 and Jim Bridger 3 and 4.
[6] At this time, there is no state or EPA requirement for SCR on Hunter 1.

PacifiCorp completed additional studies related to Hunter 1 with alternative input assumptions developed by Staff. Staff's scenario assumes that a hypothetical SCR requirement at *Hunter 3* could be negotiated to a lower cost SNCR requirement at *Hunter 3* in exchange for a firm commitment to cease coal operations at *Hunter 1* by the end of 2018. Staff's analysis is not germane to the baghouse and LNB investments outlined in PacifiCorp's Hunter 1 action item for two reasons. First, the baghouse and LNB investments are not avoided when it is assumed coal operations at Hunter 1 cease by the end of 2018. The very construct of this scenario assumes PacifiCorp implements its Hunter 1 action item to install baghouse and LNB equipment, and therefore, the scenario does not capture an alternative where these investments are not made.[7] Second, the construct of Staff's scenario assumes that the Company can negotiate a lesser compliance obligation at the Hunter 3 facility when there is no requirement for any incremental post-combustion NO_X controls at this facility in the Utah SIP. Moreover, as discussed above, there is no EPA FIP in Utah. Given there is no state or EPA requirement for post-combustion NO_X controls at Hunter 3, PacifiCorp does not have an action item for environmental investments at this facility, and as such, this analysis has no bearing on the Hunter 1 action item in the 2013 IRP Action Plan.

Staff has recently asked for additional analysis of Hunter 1. This alternative scenario analysis is similar to the request discussed above with a few differences. First, the latest request calls for a scenario in which Hunter 1 ceases coal operation at the end of 2016 instead of 2018. The request also states that the analysis should assume the Hunter 1 baghouse and LNB can be avoided. Finally, in exchange for committing to ceasing coal operation of

[7] As discussed above, it would not be valid to assume the baghouse investment, which is required by the Utah SIP and further allows the facility to achieve compliance with MATS as required by April 2015, could be avoided while the unit continues operating as a coal-fueled resource through 2018.

Hunter 1 by the end of 2016, the request assumes that a hypothetical 2023 SCR at *Huntington 2* (rather than Hunter 3) can be reduced to a hypothetical 2023 SNCR.[8]

This latest scenario is also not germane to the baghouse and LNB investments required at Hunter Unit 1 because it assumes the baghouse and LNB investments can be avoided while the asset continues running through 2016, which is not a reasonable assumption given current state and federal requirements. The baghouse is required by the Utah SIP and further allows the facility to achieve compliance with MATS as required by April 2015, and it is unreasonable to assume that the Company would continue to operate the facility when it would be out of compliance with these regulations in 2015 and 2016. Also, as was done in its original scenario analysis, Staff once again assumes the Company can negotiate a lesser compliance obligation at a different Utah coal unit that does not have a state or EPA requirement for incremental NO_X controls. Staff is requesting a flexible compliance analysis in which the Company is negotiating against itself, and effectively requesting an incremental compliance obligation that will impact customer rates. The Regional Haze rules very clearly delineate the five factors that EPA must consider when assessing BART controls for individual units when establishing a FIP. One of the five factors is the existing controls on *the unit* itself, not a hypothetical "phase out" analysis of more than one unit. Although the requested analyses are unlikely to produce relevant results, to be responsive, PacifiCorp agreed to complete them.

Consistent with its Hunter 1 sensitivities, Staff asked the Company whether shutdown of a resource like Hunter 1 would ultimately affect future compliance plans developed by the agencies responsible for administering the Regional Haze program. As noted above, the

[8] At this time, there is no state or EPA requirement for SCR or SNCR on Huntington 2.

Company's economic assessment of Hunter Unit 1 compliance scenarios does not support pursuing shutdown of the unit. In addition, due to the nature and design of the Regional Haze program long-term strategy of achieving gradual visibility improvements through 2064, absence of emissions from a given electric generation unit (EGU), or any non-EGU emission source regulated under the program, may impact the future assessment of visibility improvements and further future actions that the agencies may prescribe for remaining emissions sources in individual states. The extent and ultimate impact on the agencies' future actions through 2064 under the Regional Haze program however, would be difficult if not impossible to identify or quantify at this time. Although, it is expected that agencies will prescribe long-term actions based upon their assessment of the most cost effective remaining visibility improvement/emissions reductions opportunities on future emissions sources, which often time are most readily quantified on EGUs.

<u>Screening Model</u>

In response to parties' comments supporting use of the coal screening model instead of the System Optimizer model, PacifiCorp re-emphasizes the limitations of the coal screening tool. The screening model was developed as part of the 2011 IRP process as a means to prioritize more detailed analysis using the System Optimizer model, which was presented in Confidential Appendix A of PacifiCorp's 2011 IRP Update. The screening model was not used to evaluate economic benefits for any given environmental investment decision and is not the appropriate tool for such an evaluation. PacifiCorp explicitly cautioned parties in the 2011 IRP acknowledgement process that the screening model should only be used as a tool to prioritize more detailed system modeling of individual coal unit investments, as was done in that docket, due to the following limitations:

- Compliance alternatives are limited to early retirement;
- Natural gas conversion alternatives are not considered;
- Replacement resources for an early retirement alternative are limited to a natural gas combined cycle combustion turbine (CCCT);
- The CCCT replacement resource is scaled to precisely match the size of the coal unit being retired;
- The CCCT replacement resource comes on-line concurrent with a coal unit retirement;
- The resource portfolio implications of early retirement, including the type, timing, and location of DSM, market purchases, and other full-sized supply side resources alternatives are not captured;
- As a spreadsheet-based tool, the screening model cannot capture system constraints, including transmission and system balancing sales and purchases; and
- The screening model relies on a simplified representation of unit dispatch for both the coal-fired resources and the CCCT replacement resources.

The screening model is simply not configured nor well-suited to evaluate flexible compliance scenarios because it cannot capture the system implications of these alternatives. In contrast, the System Optimizer model simultaneously and endogenously evaluates capacity (portfolio impacts) and energy tradeoffs (system dispatch and transmission constraints) when evaluating the full range of compliance alternatives, such as moving forward with an environmental investment, retiring a unit early, or converting a unit to natural gas. PacifiCorp is committed to working with parties to improve the transparency of the System Optimizer model by providing model inputs and more detailed model outputs;

however, the Company does not view the screening model as an alternative tool for use in evaluating environmental investments at existing coal units, especially given the complexity of the analyses being requested by the parties.

CO_2 Price Scenarios

The parties commented that additional scenarios with a wider range of CO_2 prices (particularly high CO_2) should be required in light of the June 2013 Presidential Memorandum. PacifiCorp recognizes that parties have different opinions on potential costs resulting from pending regulation of CO_2 emissions applicable to existing natural gas and coal resources. PacifiCorp also notes that despite issuance of the June 2013 Presidential Memorandum, there is tremendous uncertainty about the regulatory mechanisms that might be used in EPA's pending rule-making process, and consequently there continues to be uncertainty in the cost for future regulations on CO_2 emissions from existing sources. This uncertainty is the reason that PacifiCorp has evaluated a range of CO_2 price scenarios in the 2013 IRP and in the financial analyses included in Confidential Volume III that support the Company's coal resource action items.

PacifiCorp has reviewed the June 2013 Presidential Memorandum in which President Obama directed the EPA to complete greenhouse gas (GHG) standards for both new and existing power plants. For existing sources, EPA was directed to issue "standards, regulations, or guidelines, as appropriate" that address GHG emissions from modified, reconstructed, and existing power plants.[9] PacifiCorp notes that the Presidential Memorandum did not explicitly set forth regulations for existing coal plants. The proposed standards, regulations, or guidelines are to be issued by June 1, 2014, finalized by June 1,

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

2015, with implementation of regulations as proposed in SIPs required by June 30, 2016. EPA would then review the implementation plan proposed by each state. Accordingly, even if EPA follows the President's aggressive schedule, the effective compliance dates for these standards, regulations, or guidelines are a number of years into the future.

The June 2013 Presidential Memorandum did not detail how EPA will approach CO_2 regulation or what the resulting standards, regulations, or guidelines will ultimately entail for existing resources. Parties raising the Presidential Memorandum as an issue in this IRP docket have argued that its very existence indicates that CO_2 price assumptions should be higher and start sooner. But, absent any information on how EPA intends to proceed with its rule-making process, and without any information on how individual states will propose to implement those regulations through a SIP, there is currently no means to develop a specific CO_2 price assumption that accurately reflect potential CO_2 regulation.[10]

Considering the foregoing, and contrary to the comments from some parties, the CO_2 assumptions used in the 2013 IRP remain reasonable.[11] The IRP assumptions already represent a wide range of policy mechanisms that might be used to regulate CO_2 emissions in the power sector at some point in the future. The range of assumptions are based upon independent third- party price projections, with a high scenario that is consistent with prominent legislative proposals, and with even higher scenarios developed consistent with stakeholder input during the pre-filing public input process for this IRP. This approach was taken because, as of today, there are a wide range of potential future policy tools that may be employed to regulate CO_2 emissions. Because the June 2013 Presidential Memorandum does

[10] While some groups have made recommendations to EPA, EPA has provided no indication of how it plans to proceed through its rulemaking process.
[11] In its comments to the Commission at the October 28, 2013 special public meeting, RNP supported the Company's position that the range of CO_2 price assumptions used in the 2013 IRP is reasonable.

not direct a particular type of regulatory approach, it does not make one particular approach more or less likely and therefore does not change the IRP assumptions. Similarly, because there is no detail on which to base an analysis, it does not make a particular CO_2 price forecast used in the IRP more or less reasonable.

In addition, it is important to note that the IRP assumptions and analyses were completed well before June 25, 2013. Given the timeline set forth in the Presidential Memorandum, the Company will have multiple opportunities to re-evaluate its CO_2 price assumptions before and after the issuance of proposed regulations in June 2014.[12] As assumptions are developed for the 2015 IRP, the Company will re-evaluate current market conditions and policy developments along with current forecasts from external sources in establishing updates, if any, to its CO_2 price assumptions.

Proposed Framework for Future Coal Analysis

PacifiCorp understands that parties want to see financial analysis of coal units beyond those included in the 2013 IRP Action Plan. The Company supports providing financial analysis of its environmental investment decisions for specific assets so that parties can have an opportunity to review and comment on those decisions before a prudence review in a future general rate case. However, the IRP planning cycle does not align with the compliance schedules driven by state environmental regulatory agencies, EPA, and the courts. PacifiCorp therefore does not support Staff's recommendation to expand coal unit investment analysis in this IRP docket for units other than those already addressed in the 2013 IRP Action Plan. For those units outside of the 2013 IRP Action Plan, there is no analysis that could provide meaningful information regarding any specific action, whether

[12] PacifiCorp's review of current third-party CO_2 price forecasts shows that despite issuance of the Presidential Memorandum, these forecasters have not materially altered either their assumed CO_2 start date or price level.

that action is to proceed with installing emission control equipment, converting a unit to natural gas, or to retiring a unit early.

For Cholla, PacifiCorp continues to engage in discussions with Arizona Public Service Company, the operator of the Cholla facility, and to analyze potential alternatives that might settle ongoing litigation filed with the Ninth Circuit Court of Appeals.

For those units listed by Staff and located in Wyoming, EPA has yet to finalize unit specific requirements identified in its re-proposed FIP. EPA is currently under a consent order to complete their final action on the Wyoming FIP by January 10, 2014. The Company is actively engaged in the Wyoming FIP procedural docket and is not currently proposing to pursue installation of SCR on Dave Johnston Unit 3, Naughton 1, or Naughton 2. In fact, the Company has argued against the installation of such modifications in its public comments submitted in that docket.[13] Should EPA ultimately require SCR on these units within five years of its final action, PacifiCorp will rigorously review its compliance alternatives to those investments and review such analyses with Staff and parties at the appropriate time and under the appropriate regulatory docket established for review.

Similarly, for those units located in Utah, the only known requirement for NO_X controls is the LNB required by the state of Utah for Hunter 1. Neither the state of Utah nor EPA has identified specific future requirements for SCR equipment on any of PacifiCorp's Utah coal units. PacifiCorp understands it is important to consider that there may be potential future investments, and this was done in the 2013 IRP by capturing the impact of prospective coal unit investment decisions in its portfolio development process. But it is not reasonable to request that the Commission acknowledge an action for a coal unit that is not currently

[13] PacifiCorp's comments can be accessed via the following link:
http://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2012-0026-0149

required by state or federal law. Simply stated, any analysis related to those units not currently identified in the 2013 IRP Action Plan is premature and would not provide useful information for the Company in making a decision or for the Commission in considering acknowledgment of the 2013 IRP.

Rather than extending the current IRP docket, PacifiCorp proposes to develop a new planning and review process in Oregon that addresses the parties' concerns. PacifiCorp suggests that the Commission open a new, ongoing docket for PacifiCorp that would allow the Company and parties to develop parameters for coal unit investment analysis and for the Company to seek advance Commission review of unit-specific environmental investments. The initial purpose of the docket would be to obtain certainty about the analysis to be conducted. This docket would then continue as a venue for the Company to seek acknowledgment of individual investments and would operate in tandem with the Company's biennial IRP filing, in which the Company would continue to conduct a broader, fleet-wide analysis of future investments in existing coal plants and other resources. PacifiCorp supports this process for the following reasons:

- PacifiCorp and other stakeholders developed a certificate of public convenience and necessity (CPCN) process in Wyoming to address similar concerns to those now voiced by Oregon stakeholders. PacifiCorp has also used the Voluntary Request for a Resource Decision process in Utah to allow stakeholder vetting of environmental investments at Jim Bridger Units 3 and 4. While the proposed Oregon process is not a pre-approval process, it allows a thorough, advance vetting of specific investments in coal plants and proposals to close or retrofit coal plants.[14] It results in a Commission order that provides all stakeholders clarity about the advisability of such investment or non-investment plans. The process has worked well in Wyoming and Utah, and the Company would like to use a similar process in Oregon.

- Oregon's CPCN statute, ORS 758.015, is narrower than the CPCN statutes PacifiCorp operates under in Wyoming and Utah, and it does not provide an appropriate procedural vehicle for plant-specific investment review. Oregon's statute requires a CPCN only when a utility is building a transmission line that requires condemnation of land. In comparison, Wyoming's CPCN statute provides that "No party shall begin construction of a line, plant or system or of any extension of a line, plant or system without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction."[15]
- In the Commission's orders adopting and refining the IRP process, the Commission has used its general ratemaking authority to adopt broad resource planning guidelines for Oregon's investor-owned energy utilities.[16] The plant-specific investment review process the Company is now proposing as a sub-set of the Commission's comprehensive IRP process is fully consistent with these orders and with OAR 860-027-0400, the Commission's rule on resource planning. In fact, the process responds directly to the Commission's stated expectations in Order No. 12-493 that a utility

[14] *See In re Rocky Mountain Power*, Docket No. 20000-384-ER-10 (Record No. 12702) (Sept 22, 2011) (while the CPCN "process does not require the Commission to pre-approve such projects," it provides a "means to consider the prudence of major capital investments before millions of dollars have already been invested.")
[15] W.S. 1977 37-2-205. Utah's CPCN statute is similarly broad.
[16] *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket UM 180, Order No. 89-507 (Apr. 20, 1989); *In re Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 (Jan. 8, 2007).

"fully evaluate all major investments that have implications for the utility's resource mix—including those where the investment will extend the useful life of an asset and where a plant shutdown is an option—in its IRP."[17] At the same time, a plant specific review process permits the comprehensive IRP process to continue under its current schedule and guidelines, while at the same time facilitating an on-going review of plant-specific investments whose timing are not well aligned with the IRP planning cycle.

- Because PacifiCorp's proposed process would result in acknowledgement of plant-specific investments, rather than pre-approval, the process does not implicate concerns about the legal authority of the Commission to bind future commissions. The Commission previously has exercised the authority to make a conditional finding of prudence, which is similar to what could result from PacifiCorp's proposed IRP investment review process. *See In re Northwest Natural Gas Company dba NW Natural*, Docket UM 1520, Order No. 11-176 (May 25, 2011).
- An investigation is less suitable than a new, ongoing docket for plant-specific investment review because investigations are typically generic proceedings with a defined scope and limited duration. PacifiCorp needs an ongoing, Company-specific process to respond to stakeholders' requests for information well in advance of PacifiCorp's investment decisions in its coal plants.

<u>Demand Side Management</u>

In addition to recommendations specific to coal resources, Staff presented specific recommendations to the Commission related to DSM action items. Specifically, Staff

[17] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 246, Order No, 12-493 at 33 (Dec. 20, 2012).

recommended yearly reporting to increase accountability for DSM performance in states other than Oregon, as well as developing targets for DSM in other states and disallowing costs in rate proceedings if those targets are not met. Staff noted that PacifiCorp cancelled or delayed action items from the 2011 IRP action plan and stated that the current proposed action items do not sufficiently capture benefits of accelerated DSM. Finally, Staff proposed a new action item to "[r]einstate the canceled commercial curtailment project and move forward with delayed direct install and commercial RFP."

After further discussion with Staff, it appears that concerns about accountability for DSM actions items and DSM in other states are primarily related to inadequate communication. PacifiCorp sets DSM targets consistent with the bi-annual IRP process and incorporates these targets into its business planning process, where DSM resource acquisition targets are set for each state. PacifiCorp acknowledges that it can improve its communication and outreach about its DSM resource acquisition activities outside of Oregon to stakeholders within Oregon. To this end, PacifiCorp is open to providing the Commission and Oregon parties, during Commission public meetings, an update on its DSM resource activities outside of Oregon on a periodic basis, similar to routine updates provided by the Energy Trust of Oregon (ETO).

Staff also recommended that the residential and small commercial direct install RFP be reinstated. The Company acknowledges that it should have provided an update on the status of these actions items to Staff and other interested parties. The RFP was initially released in March 2012, and was intended to accelerate the acquisition of energy efficiency resources in advance of the 2016 resource need identified in the 2011 IRP. The preliminary results of the RFP, which were received in April 2012, were reported in an updated Needs

Assessment filed with the Commission in Docket No. UM 1540 as part of the all-source RFP and consistent with the 2011 IRP Action Plan. Given a reduced resource need as documented in the updated Needs Assessment, the all-source RFP was cancelled in September 2012.

Despite the revised Needs Assessment, the Company is moving forward with the residential and small commercial direct install RFP. The initial delay was necessary to await the revised 2013 IRP demand-side resource decrement value analysis (avoided cost values) needed to complete cost-effectiveness screening. The procurement award on the business sector proposal was made in October 2013. Contract negotiations are underway, and the regulatory filings necessary for the business sector direct install program implementation will begin by the end of 2013.

In reviewing the residential direct install proposals, the Company determined the RFP proposals received were materially the same and similar to an existing offer already under development within an existing Company program. As a result, the Company cancelled the residential sector portion of the RFP in August 2013. To ensure competitive pricing and the best possible program design, the Company has re-scoped the request for direct install/direct distribution proposals and is scheduled to re-release a residential-only RFP by the end of 2013, with regulatory filings to begin in the first quarter of 2014.

For the same reason the all-source RFP was cancelled (the revised Needs Assessment), the Company made the decision in late September 2012 not to move forward with finalizing the Commercial Curtailment agreement. The revised needs assessment negatively impacted the product’s cost-effectiveness, which led to the Company’s decision. The implementation of the Commercial Curtailment product, however, was a 2011 IRP Action Plan item, and as such the Company should have communicated its decision to Staff and other interested parties at the time the decision was made. The Company will communicate such decisions going forward.

4. COMMISSION STAFF OPENING COMMENTS

Environmental Investment in Coal Resources

Staff provides general comments on the information, assumptions and action items that are provided in PacifiCorp's 2013 IRP related to environmental investments for existing coal units. Specifically, Staff addresses the following in its opening comments:

- Staff states it is evaluating potential shut down scenarios for Hunter Unit 1 and Dave Johnston Unit 3, noting that additional model runs were requested from the Company.
- Staff continues to investigate whether baghouse and low NO_X burner investments at Hunter Unit 1 can be avoided and does not currently support Action Item 8b in the 2013 IRP Action Plan.
- Staff states it has not seen an analysis of environmental investments for Cholla Unit 4 and is considering recommending the Commission require the following in the 2013 IRP Update:
    - "A Detailed economic analysis of compliance and shutdown/conversion options."[18]
    - "A flowchart showing key milestones and a timeline for installing an SCR at Cholla by the compliance deadline of the end of 2017."[19]
    - "A flowchart showing key milestones and a timeline with dates and key milestones for retiring Cholla and replacing the energy and capacity as needed with the next best alternative."[20]

[18] LC 57, Opening Comments of the Public Utility Commission of Oregon Staff, p. 4.
[19] *Ibid.*

- Citing recent Environmental Protection Agency (EPA) actions in both Utah and Wyoming, Staff states that PacifiCorp's base case Regional Haze assumptions are outdated for certain coal units. Staff is seeking additional information on how EPA's actions in Wyoming will impact specific pollution control upgrades.
- Staff is pleased PacifiCorp has analyzed alternative compliance scenarios and states that these types of analyses should be included in future IRPs and IRP Updates.
- Citing the June 2013 Presidential Memorandum, Staff is requesting information on how the Company is evaluating the risks of forthcoming EPA requirements.
- Staff notes that PacifiCorp did not provide financial analysis of investments required at the jointly owned Craig and Hayden plants, and citing Order No. 12-177 in Docket UE 233, states it is still considering how to address this issue.

In response, PacifiCorp refers to the discussion of environmental investments in coal units included above and provides the following additional information.

Regarding Staff's comments on the jointly owned Hayden units, PacifiCorp notes that the environmental investments at these facilities are required by state law. Specifically, the state of Colorado promulgated and EPA approved, a Regional Haze SIP with specific requirements for Hayden 1 and Hayden 2. Further, the state of Colorado adopted the Clean Air Clean Jobs Act, which requires installation of emission controls at Hayden 1 and Hayden 2. Finally, the Colorado Public Service Commission found installation of SCR to be reasonable and prudent through a CPCN application filed by the Public Service of Company of Colorado as the operator agent of the Hayden facility.

[20] *Ibid.*

Regarding Staff's comments on the jointly owned Craig units, PacifiCorp notes the environmental investments required at Craig 1 and 2 are also included in the Colorado SIP approved by EPA. Unlike the Hayden investments, the Craig investments are not required under Colorado's Clean Air Clean Jobs Act, and the Colorado Public Service Commission does not have regulatory authority over Tri-State Generation and Transmission Association, Inc. (Tri-State) as the operator of the Craig facility. Nonetheless, in compliance with the Colorado SIP, Tri-State plans to install NO_X controls on Craig 1 and 2.

In addition, prior to the joint owners approving the installation of SCR at Hayden Units 1 and 2 and Craig Unit 2, PacifiCorp, as a minority owner, carefully reviewed its legal options regarding the installation of emissions control equipment under the participation agreements for the respective units. Given the positions being taken by the other unit owners, PacifiCorp as a minority owner would have been forced to take the other owner's decision to install SCR to arbitration at both Hayden Units 1 and 2 and Craig Unit 2. At arbitration, in order to succeed, PacifiCorp would have to show that the other owners are acting inconsistent with the participation agreement or inconsistent with generally accepted practices in the electric utility industry. Given the legal requirements described above and the terms of the participation agreements, PacifiCorp believed it had minimal likelihood of success at arbitration.

<u>Net Metering and Distributed Generation</u>

Staff comments that it is unclear what level of distributed solar photovoltaic (PV) systems is assumed beyond the 60 MW of new solar PV assumed from the Utah Solar Incentive Program. Staff further comments that PacifiCorp identifies 7 MW of distributed solar resources in Oregon and an additional 2 MW of solar water heating potential and notes that the Company does not have an action item to pursue distributed solar resources in Oregon. Finally, in reference to Action Item 2a, Staff states that it would like to receive a copy of the Utah Solar Incentive Program annual report that will be filed with the Utah Public Service Commission.

In response, PacifiCorp notes that preferred portfolio resources labeled as "Micro Solar – PV" and identified as located in the east are distributed solar resources located in Utah. Through 2017, this includes resources from the Utah Solar Incentive Program.[21] Beyond 2017, the east "Micro Solar – PV" resources reflect distributed solar resources in Utah assuming continuation of current incentive levels. PacifiCorp further clarifies that the Oregon distributed solar and solar water heating resource quantities referenced by Staff are resource potential figures. No distributed solar resources beyond the 3.45 MW selected as part of the Oregon Volumetric Incentive Rate Program are included in the preferred portfolio. Similarly, no solar water heating resources in Oregon were selected in the preferred portfolio. Because these resources were not selected as least cost/least risk resources, the Company did not identify specific action items for these resource categories. Regarding Staff's request to receive the Utah Solar Incentive Program annual report, PacifiCorp notes that the filing will be publicly available on the Utah Public Service Commission website. PacifiCorp will inform Staff when the annual report is posted.

Renewable Resource Action Items

Staff states that Action Item 1d, which outlines PacifiCorp's approach to fulfill the Oregon small solar compliance obligation through RFPs, is reasonable. Staff further comments that the Company should plan to compare the capacity contribution of wind and

[21] Note that the distributed solar resource capacity in the preferred portfolio is grossed up to account for losses between retail voltage and wholesale transmission voltage.

solar resources using peak load carrying capability (PLCC) and effective load carrying capability (ELCC) analyses.

The Company appreciates Staff's comments and support on Action Item 1d. PacifiCorp will consider Staff's recommendation to compare the capacity contribution of wind and solar resources between alternative methods.

Carbon Costs

Staff believes that carbon costs in PacifiCorp's 2013 IRP do not reflect potential futures and references carbon pollution standards described in the President's Climate Action Plan. Staff further comments that PacifiCorp's carbon cost assumptions begin later than some estimates, are lower than some estimates, and likely need upward adjustment based on the President's Climate Action Plan. Staff also notes that PacifiCorp did not use hard cap carbon price assumptions in the stochastic risk analysis performed with the Planning and Risk model (PaR). Finally, Staff states that they are looking at whether the Company met IRP Guideline 8.c. and are evaluating the impact of carbon price scenarios on the selection of resource portfolios.

In response, PacifiCorp refers to its discussion on CO_2 price assumptions above and provides the following additional information. Regarding carbon price assumption used in PaR, PacifiCorp notes that it analyzed three different sets of CO_2 price assumptions in its stochastic risk analysis: zero, base, and high. While a hard cap scenario was not evaluated in the PaR model, the high price scenario includes CO_2 prices reaching $75 per ton. Moreover, PacifiCorp notes that the stochastic risk profiles provided as Figures L.1 through L.6 in Volume II, Appendix L of the 2013 IRP show there is not a significant relational difference among portfolios on both cost and risk metrics as CO_2 prices progress from zero to base case and then to high price assumptions. Specific to the 2013 IRP, PacifiCorp would not expect that further analysis of even higher CO_2 prices, as seen in the hard cap CO_2 price scenarios, would alter PacifiCorp's near-term Action Plan focused on procuring cost effective DSM and front office transaction (FOT) resources.

Oregon IRP Guideline 8c requires identification of at least one CO_2 compliance scenario that would "trigger" selection of a resource portfolio that is substantially different from the preferred portfolio and requires that the costs and risk of such portfolios be compared to the preferred portfolio. The guideline further requires that the Company provide an assessment of whether such a CO_2 regulatory future would be mandated. PacifiCorp satisfied Guideline 8c by evaluating a broad range of CO_2 price scenarios in its portfolio development process which generated resource portfolios that are substantially different from the preferred portfolio.[22] These portfolios include those generated using high CO_2 price assumptions (core cases C05 and C09) and hard cap CO_2 price assumptions (core cases C14 and C18). Both cost and risk metrics from these portfolios are compared to the preferred portfolio in Table 8.13, Volume I of the 2013 IRP. These portfolio cost and risk metrics are compared under base case assumptions and for high CO_2 price assumptions, which is one of the CO_2 price scenarios assumed in developing core cases C05 and C09. PacifiCorp then assesses the likelihood of CO_2 regulations at the levels that triggered those portfolios that are substantially different from the preferred portfolio at page 240, Volume I of the 2013 IRP.

Risk Metric

Staff comments that they do not agree with the risk metrics used to select the preferred portfolio, noting that two criteria were used the risk adjusted stochastic mean and

[22] Assumptions for CO_2 prices are summarized in Figure 7.3, in Volume I of the 2013 IRP. A summary of resource portfolios is provided in Figures 8.1 through 8.5, Volume I of the 2013 IRP.

the upper-tail mean less the stochastic mean. Staff explains that one portfolio might be superior with regard to the upper tail mean less stochastic mean metric but inferior using the stochastic mean by itself. Staff further states that PacifiCorp should use plots of the stochastic mean and upper tail mean in future IRPs.

In response, PacifiCorp confirms that both cost and risk metrics were used in the pre-screening and initial screening phases of the preferred portfolio selection process.[23] The cost metric used in the phase of the preferred portfolio selection process is the stochastic mean PVRR, which is the expected portfolio cost from the stochastic risk simulations produced using PaR. The risk metric used in this phase of the preferred portfolio selection process is the upper-tail mean PVRR less the stochastic mean PVRR. The upper-tail mean PVRR captures the high cost, low probability portfolio cost outcomes and is calculated as the mean of the five highest cost Monte Carlo simulations. Based on Staff's comments, its primary concern seems to be with PacifiCorp's netting of the expected cost metric (the stochastic mean PVRR) against the risk metric (upper-tail mean PVRR). PacifiCorp nets the stochastic mean PVRR against the upper tail mean PVRR to remove the effect of fixed costs, which are identical among all 100 Monte Carlo iterations and therefore not a risk variable, from the risk metric. PacifiCorp further notes that for resource portfolios analyzed in the 2013 IRP, the outcome of the initial screening process would not be affected using Staff's methodology. PacifiCorp demonstrated this outcome at its April 17, 2013 pre-filing public input meeting.

PacifiCorp agrees that portfolios can have different cost and risk profiles, which is precisely why both cost and risk metrics are used to screen resource portfolios. This is achieved by evaluating the cost and risk metrics for each portfolio in "scatter plots", with the

[23] The pre-screening and initial screening process is described at pages 212 through 218, Volume I of the 2013 IRP.

risk metric for each portfolio plotted on the y-axis, and the cost metric for each portfolio plotted on the x-axis. During the initial screening process, superior portfolios are identified as those that are either within two percent of the least cost portfolio or within two percent of the least risk portfolio. Consequently, the least cost, least risk portfolios move on to the next phase of the preferred portfolio selection process, which includes comparative portfolio analysis on risk-adjusted PVRR, reliability, emissions, and fuel diversity measures to inform selection of the preferred portfolio.[24]

<u>Front Office Transactions</u>

Referencing the amount of FOTs in the preferred portfolio, Staff states that the Company should be required to provide a detailed elaboration of its forward market view, including more analysis and justification for market depth and liquidity assumptions.

In response, PacifiCorp notes that it includes a discussion of FOT resources in Volume I, Chapter 6 of the 2013 IRP beginning at page 154. This section describes FOT resources alternatives and identifies assumed levels of availability by market location, product type, and term. PacifiCorp further describes the factors that the Company considers in developing these assumptions. PacifiCorp also includes in Volume II, Appendix J of the 2013 IRP an evaluation of western resource adequacy using the Western Electricity Coordinating Council (WECC) 2012 Power Supply Assessment. This evaluation shows sufficient regional supply, in excess of regional planning margins assumed by WECC, supporting the use of FOTs as a resource alternative in the 2013 IRP.

[24] The risk-adjusted PVRR is a metric that combines both cost and risk elements of a portfolio into a single metric by taking into account the likelihood of high risk outcomes.

Direct Access Loads

Staff references IRP Guideline 9 and the open Docket No. UE 267 in stating that future IRPs will need to project future permanent direct access loads and remove such loads from system generation requirements.

In response, PacifiCorp notes that it does not currently have any customers that have gone to direct access on a permanent basis, and therefore it continues to plan for load for direct access customer load. Docket UE 267 remains open, and the Company will evaluate whether any of its planning assumptions will need to be modified after a final order is issued in that docket.

Natural Gas and Electricity Prices

Staff comments that it is studying how prices at different hubs are correlated and how natural gas prices and electricity prices are correlated in their review of stochastic price forecasts. Staff recommends that the stochastic prices be included in the IRP.

In response, PacifiCorp notes that it describes its stochastic model and publishes assumed natural gas and wholesale electricity price correlation parameters in Chapter 7, Volume I of the 2013 IRP. Natural gas to wholesale electricity price correlation parameters are published among two different natural gas price locations (East and West) and five different wholesale electricity price points of delivery. These data are further provided among four seasons. Publishing stochastic prices within the IRP is not an efficient means to deliver stochastic model data. Publishing natural gas and power price data among multiple points of delivery, among different price curve scenarios, across 100 Monte Carlo simulations performed over a twenty year planning period would not likely provide much value to most stakeholders. For those stakeholders, such as Staff, that might want to review and analyze these data, it would be more efficient that these data be supplied upon request, which would allow the information to be distributed in an electronic format. It is unlikely stakeholders would choose to manually enter such an extensive data set from the IRP into an electronic file format.

Coal Prices

Staff comments that in future IRPs it would be beneficial to analyze larger changes in projected coal prices due to uncertainty in coal mining regulation, coal transport regulation, carbon regulation, and a changing resource mix that can impact worldwide demand for coal. Staff further states that PacifiCorp should continue to analyze the economics of fuel conversion opportunities.

PacifiCorp will consider Staff's recommendations in developing coal price scenarios for future IRPs. As was done in the 2013 IRP, commodity price assumptions are routinely discussed with stakeholders during the public process. PacifiCorp further notes that it plans to continue analyzing natural gas conversion opportunities in future IRPs.

Renewable Portfolio Standard Compliance

Staff states that the preferred portfolio alone does not meet Washington's RPS requirements, noting that compliance would be achieved with renewable energy credits (RECs). Staff concludes that the Company's analysis demonstrates that this is an appropriate approach. Nonetheless, Staff believes that a price for RECs should be considered for planning purposes. Staff states that the Company should provide an expected cost of meeting compliance with RECs and then establish factors causing REC price variability supporting a range of REC prices over time. Staff further comments that PacifiCorp's RPS modeling approach appears to be computationally intensive, and it looks forward to working with the

Company to develop less intensive ways to determine costs for complying with state RPS requirements. Finally, Staff states that PacifiCorp should consider alternatives allowing all renewable resources to meet Oregon RPS requirements.

While PacifiCorp agrees with Staff's comments that the Company's IRP analysis supports use of RECs to meet Washington RPS requirements, the Company does not agree with Staff's recommendation to establish a twenty year REC price forecast to be used for planning purposes. Considering that the REC market lacks transparency, PacifiCorp is concerned that publishing a REC price projection in the IRP could influence prices when the Company looks to sell or purchase RECs in the market. This could harm customers and would not be in the public interest. As was done in the 2013 IRP, the Company believes that it is reasonable for it to consider the upper limits of future REC prices in the context of state-specific RPS rules and current market conditions when evaluating compliance alternatives for any given state RPS program.[25] Through its planning processes, PacifiCorp will continue to monitor REC prices and update its RPS compliance plans consistent with state RPS rules and consistent with changes in market conditions. Moreover, PacifiCorp notes that there is presently no framework to establish a REC price projection that would be consistent with other environmental policy, power price, natural gas price, CO_2 price, and resource cost assumptions specific for any given scenario used in the portfolio development process.

In response to Staff's comments on the RPS modeling approach, PacifiCorp agrees that the RPS modeling framework adopted for the 2013 IRP was computationally intensive; however, PacifiCorp notes that this framework was adopted to capture the impacts of state RPS programs on resource selections in any given portfolio. The modeling approach required

[25] Please refer to Chapter 8, Volume I beginning at page 224 under the heading "Final Selection".

developing resource portfolios without RPS requirements to determine the level of incremental renewable resources that would be part of a least cost portfolio. For RPS allocation purposes, the energy from such resources was allocated on a system basis. In as much as these system resources were not sufficient to achieve compliance with state specific RPS targets, a second resource portfolio was developed with additional RPS-eligible renewable resources used to fulfill the incremental compliance need of each state. Because the allocation of energy from renewable resources to jurisdictions having state RPS requirements affects the total amount of renewable resources required to meet RPS targets, the renewable energy allocation among states affects the need for other resources in the portfolio. Consequently, the modeling framework used in the 2013 IRP not only ensures that state-specific RPS requirements are met consistent with the RPS rules of each state but also further ensures that the impact of RPS requirements for any given jurisdiction on the broader resource portfolio is captured. Nonetheless, PacifiCorp is continuously evaluating process improvements and will continue to work with stakeholders, including Staff, to explore alternatives to capturing the effects of RPS compliance during the portfolio development process in future IRPs.

In the context of its IRP, PacifiCorp does not support Staff's recommendation that the Company revise its modeling approach to allow all resources to meet Oregon RPS requirements. PacifiCorp views Staff's recommended approach as an alternative cost allocation method that would be better suited for the Multi-State Process (MSP). The Company notes that the IRP and MSP are two distinct and different processes with different goals. The IRP is focused on long range resource planning. The MSP is concerned with allocating costs among states based on defined allocation methodologies.

Transmission Expansion

Staff continues to review transmission-related action items in the 2013 IRP. PacifiCorp will continue to support Staff, as requested, in this review.

Load Forecast

Staff notes that PacifiCorp generated high and low load growth scenarios used to generate sensitivity case resource portfolios. Staff states that the Company should provide stochastic modeling results for these portfolios. Referencing PacifiCorp's response to OPUC data request 74, Staff further comments that PacifiCorp did not identify a 95th percent confidence interval for load growth.

PacifiCorp did not perform stochastic analysis on portfolios developed using high and low load growth assumptions due to the incomparability of stochastic analysis of load growth scenarios relative to other resource portfolios. Incremental resources are based upon load projections that include either fewer resources (in the case of low load assumptions) or more resources (in the case of high load assumptions), and therefore include different levels of fixed costs associated with each respective portfolio. Considering that fixed costs are not stochastic variables, results from stochastic modeling performed on load sensitivity portfolios would not be comparable to any other resource portfolio developed in the IRP.

PacifiCorp further notes that since Staff submitted its opening comments in August 2013, the Company completed a stochastic model run for a load sensitivity case defined by Staff in a data request. Staff's sensitivity was based on an alternative resource portfolio, developed using low load assumptions, analyzed in PaR assuming the base case load forecast. The results of this sensitivity showed that Staff's alternative portfolio produced higher expected costs as compared to the 2013 IRP preferred portfolio. In its reply to Staff's data request, PacifiCorp noted that the portfolio created with the low load forecast does not meet the 13 percent planning reserve margin supported by the Company's LOLP study when evaluated against the medium load forecast as used in the PaR studies. As a result, when Staff's alternative resource portfolio is analyzed in PaR, incremental system balancing purchases, considered to be non-firm for capacity planning purposes, are used to meet load. Consequently, the amount and cost of energy not served (a measure of reliability) between the Staff's alternative resource portfolio and PacifiCorp's 2013 IRP preferred portfolio are not directly comparable. The Company further noted in its reply to Staff's data request, that the 2013 IRP LOLP study establishes reliability metrics using only firm system capacity resources to prohibit the use of system balancing purchases to maintain system reliability.

In response to Staff's comments on the 95 percent confidence interval for the load forecast, Staff states the Company's response to staff data request 74 indicates that a 95th confidence interval has not been estimated. Staff data request 74 references Volume I, page 193, which shows the total load forecast for the IRP. The Company cannot provide a 95 percent confidence interval for the total IRP load forecast because the prediction error for all of the variables used in each of the state and class models, as well as individual customer forecasts and demand side management forecasts, would need to be included to calculate a 95 percent confidence interval. Estimating the prediction uncertainty in each of the forecast components would include the economic drivers, normal weather, and demand side management forecast as well as Bonneville Power Southeast Idaho forecast and customer account manager forecasts for large industrial customers. The prediction error of the IHS Global Insight economic forecasts, customer level forecasts and demand side management forecasts are unavailable to the Company. However, the Company has provided the 95 percent confidence interval information for each class level sales forecast by state in its response to Staff data request 58.

Demand Side Management

Staff comments that the preferred portfolio contains less DSM than what was in the 2011 IRP Action Plan. Staff also notes that some DSM action items from the 2011 IRP were not completed specifically, the action item to procure cost effective resources through residential and small commercial programs outside of Oregon and the action item to review current staffing levels. Staff further comments that the preferred portfolio does not contain Class 1 or Class 3 DSM resources and notes that it is investigating whether the costs for these resources are overestimated. Finally Staff references Oregon IRP Guideline 4e in encouraging PacifiCorp "to participate in ongoing efforts by the Energy Trust of Oregon to potentially anticipate and quantify technological advances related to energy efficiency."[26]

In response, PacifiCorp refers to the discussion of DSM provided above and provides the following additional information. PacifiCorp notes that despite a reduced resource need in the 2013 IRP, the 2013 IRP Action Plan contains more Class 2 DSM resources than was identified in the 2011 IRP. Staff's assessment of the Class 2 DSM resources in the 2013 IRP and 2011 IRP action plans is not accurate because it uses incorrect estimates of 2016 targets from the 2011 IRP Action Plan and then compares these targets to 2015 targets in the 2013 IRP Action Plan. The 2011 IRP action item on Class 2 DSM reads:

> "Acquire at least 900 MW and up to 1,800 MW by 2020, equivalent to at least 4,533 GWh and up to 9,066 GWh. Acquire at least 520 MW and up to 1,000 MW of cost-effective Class 2 DSM by 2016."

[26] Guideline 4e requires: "Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology".

Staff appears to have scaled the MW targets for the period 2016 to 2020 to arrive at an estimate a range of GWh targets by 2016:

- 520 MW/900 MW = .578 x 4,533 GWh = 2,619 GWh (Staff references 2,600 GWh in its opening comments)
- 1,000 MW/1,800 MW = .556 x 9,066 GWh = 5,037 GWh (Staff references 5,000 GWh in its opening comments)

The 2013 IRP action item on Class 2 DSM reads:

> "Acquire 1,426 – 1,876 GWh of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017."

It is not clear why Staff chose to compare an estimate of *2016* energy efficiency targets from the 2011 IRP with the *2015* energy efficiency targets identified in the 2013 IRP. Nonetheless, the correct figure from the 2011 IRP for the 2015 target is 1,186 GWh to 2,372 GWh. Comparing 2016 targets shows that the 2013 IRP includes more energy efficiency resources (1,872 GWh) as compared to the 2011 IRP (1,677 GWh). Both the 2011 IRP and the 2013 IRP reflect an aggressive approach to DSM, and the 2013 IRP Action Plan produces a higher initial target despite advancing lighting standards. The upper ends of the ranges are not ceilings but rather represent a range of possible outcomes. In the 2011 IRP the upper end of the range was derived by simply doubling of the initial target value. In the 2013 IRP, the range of DSM acquisition in the Action Plan is derived from the preferred portfolio, with 2014 and 2015 targets taken from case C15, which includes accelerated DSM input assumptions.

Staff also called into question whether key activities within the 2011 IRP Action Item 6 were materially completed, specifically:

- System-wide RFP on direct install/direct distribution

- Implementation of a commercial curtailment product; and
- Providing a review of the sufficiency of current staffing levels.

In response to the Staff's comments on the staffing sufficiency analysis, as noted in Chapter 9, Volume I at page 259 of the 2013 IRP, PacifiCorp completed a review of staffing levels to achieve programmatic cost effective efficiency targets. The process consisted of a series of meetings and discussions with internal staff, external delivery personnel and executive management. The actions taken as a result of those reviews included:

- The addition of four full-time equivalent resources since May 2012.
- The Company has begun consolidating its stand-alone business programs into a single program "Wattsmart Business", which will streamline program administration requirements and improve overall program performance.
- The Company expanded the contract scope of its small to mid-market business sector trade ally coordinator to relieve demands on Company project managers while increasing project activity and throughput.
- The Company released a residential and business sector direct install/direct distribution request for proposal to seek additional delivery partners and increase savings opportunities.
- The Company is making new investments in its demand side management delivery, tracking and reporting systems to further reduce the administrative requirements on current staffing.
- The Company completed an outsourcing of its Utah and Idaho irrigation load control program before the 2013 summer control season. This reduced staffing demands and allowed Program Management resources to assist on other projects.

In response to Staff's concerns regarding the possible overstatement of Class 1 and Class 3 DSM resources costs as a possible explanation for their lack of selection in the 2013 IRP, the Company provides two comments. First, the assumed costs are based on a recent market assessment completed by an independent consultant. The detailed cost assumptions and data sources are well documented and provided in the recent Conservation Potential Assessment that was used to inform the 2013 IRP modeling effort. Second, with a reduced resource need in the 2013 IRP, the need for near-term capacity resources has been deferred to the latter half of the 20 year IRP planning horizon, well beyond the period in which PacifiCorp develops IRP Action Items.

Finally, in response to Staff's reference to Oregon IRP Guideline 4e and statement encouraging PacifiCorp "to participate in ongoing efforts by the Energy Trust of Oregon to potentially anticipate and quantify technological advances related to energy efficiency," the Company agrees that it can more effectively communicate how it currently accounts for emerging technologies and how it actively works with the ETO and other parties to ensure a comprehensive measure set is assessed and used in the resource planning process. Both PacifiCorp and the ETO consider emerging technologies in their conservation potential assessments in a similar manner and are informed by similar sources, which include the Northwest's Regional Technical Forum, the Northwest Energy Efficiency Alliance (NEEA), and others. Both PacifiCorp and the ETO include emerging technologies such as light emitting diodes, heat pump water heaters, and mini-split ductless heat pumps, and both entities regularly compare resource measure lists against each other for comprehensiveness. The Company will continue to work closely with the ETO on resource planning and related matters to improve these types of alignments, and will improve its communication and collaboration efforts with Staff and other interested parties.

<u>Supply Side Resource Cost</u>

Staff supports PacifiCorp's assumptions for supply side resource options, noting that all commercially viable resource options are included, that costs are consistent with industry averages, and that the costs are supported with documentation.

The Company agrees with Staff's assessment of supply side resource options considered in the 2013 IRP and appreciates Staff support.

<u>Planning and Modeling Improvements</u>

Staff comments that portfolios developed with low natural gas prices have higher risk when analyzed in PaR and states that for this reason, portfolios C4, C5, C8 and C9 are prescreened and excluded from further consideration. Staff states it will continue to look at implications of this effect on portfolio selection.

In response, PacifiCorp suggests that Staff review the full suite of input assumptions used to develop those portfolios listed in its comments. For instance, each of these cases were developed assuming low natural gas prices paired with high CO_2 price assumptions and high coal price assumptions. Consequently, these portfolios yield significant coal unit retirements and natural gas conversions as summarized in Figures 8.1 through 8.5 in Chapter 8, Volume I of the 2013 IRP. With significant early retirements, PacifiCorp's resource portfolio is increasingly dominated by natural gas-fired generation, and with reduced fuel diversification, is more susceptible to volatility in natural gas prices. The aforementioned resource portfolios are not only higher risk, they are also higher cost driven by significant new resource costs required to replace existing coal units that retire early.

Assessment Tools

Staff comments that it is evaluating whether the System Optimizer model is agile enough to accomplish the type of analysis required for environmental investments in coal resources. Staff notes the System Optimizer analysis is comprehensive and rigorous, but cumbersome and not conducive to running multiple scenarios. As an example, Staff characterizes the Company's response to Staff Data Request 28 as stating no sensitivities were performed for alternative compliance deadlines that might be contemplated under a more stringent regional haze scenario. Staff concludes by noting "it is important to be able to evaluate additional alternatives and performance of each under various future scenarios."

In response, PacifiCorp refers to its discussion of the limitation of the screening model included above. PacifiCorp reiterates that the System Optimizer model is the appropriate model for analysis of environmental investments that include early retirement and natural gas conversion as compliance alternatives. The System Optimizer model can simultaneously and endogenously evaluate capacity (portfolio impacts) and energy tradeoffs (system dispatch and transmission constraints) when evaluating the full range of compliance alternatives, including whether to move forward with an environmental investment, retire a unit early, or convert a unit to natural gas. PacifiCorp is committed to working with parties to improve the transparency of the System Optimizer model by providing model inputs and more detailed model outputs; however, the screening model is not an appropriate alternative tool to evaluate environmental investments at existing coal units.

Public Process

Staff commends the Company on its efforts to provide information and to gather public input before filing the IRP. Nonetheless, Staff notes the coal investment analysis was not made available for significant review and comment before the filing. Staff states that in the future, the coal investment analysis should be made available before filing.

PacifiCorp recognizes that Staff, and other parties, would have liked to see coal unit investment analysis sooner in the process. Unfortunately, PacifiCorp was unable to finalize its coal unit investment analysis while concurrently completing the extensive core case and stochastic risk analysis modeling required for the 2013 IRP. As discussed in the Company's response to comments from the October 28, 2013 special public meeting, PacifiCorp is recommending a new process that will allow parties to review coal unit investment analysis going forward. Moreover, PacifiCorp is exploring IRP process improvements and will work with Staff and other stakeholders to implement these improvements for the 2015 IRP planning cycle.

5. CUB OPENING COMMENTS

Energy Efficiency

CUB comments that despite high portfolio rankings for scenarios assuming accelerated acquisition of DSM resources, PacifiCorp chose not to prioritize these portfolios. CUB further states that it is not known how accelerated DSM would impact FOTs and other resources. CUB presents its own analysis to support claims that energy efficiency is being implemented at a greater rate in Oregon via the ETO as compared to other states and uses this analysis to assert PacifiCorp should be making more investments in energy efficiency. CUB recommends "that the Company consider modeling different strategies, such as ETO-comparable programs in other states".

PacifiCorp disagrees with CUB's comments about 2013 IRP portfolios developed using assumptions for accelerated DSM acquisition. PacifiCorp worked extensively with stakeholders over the course of four public input meetings held between June 20, 2012 and September 14, 2012 to develop assumptions for the portfolio development process. Throughout this process, PacifiCorp received many requests from a diverse and engaged stakeholder group, which included requests to generate a portfolio assuming accelerated ramp rates for Class 2 DSM resources. At that time, PacifiCorp communicated that it did not have the data required from its Conservation Potential Assessment to develop accelerated market and measure ramp rates at the two percent of retail sales level of acquisition or to ascribe the incremental cost that might be required to achieve this level of accelerated acquisition of DSM resources. Nonetheless, to be responsive to stakeholder requests and as a means to test how accelerated DSM inputs might affect overall portfolio results, PacifiCorp developed high level assumptions to derive inputs required for this analysis.[27]

The accelerated DSM assumptions were applied in portfolio C15, which also precluded selection of CCCT resources consistent with stakeholder input. As noted by CUB and other parties, this portfolio ranked high when compared to other portfolios. Despite this ranking, PacifiCorp did not consider it as a candidate for the preferred portfolio and explained its rationale for this decision in Chapter 8, Volume I of the 2013 IRP at page 222. Not only did this portfolio preclude selection of CCCT resources, a proven technology, throughout the entire planning period, PacifiCorp stated its concerns about whether the accelerated ramp rates could be delivered at the costs assumed for this scenario. Because PacifiCorp takes the DSM targets in the IRP seriously and holds itself accountable for delivering on its goals, consistent with its statements made to stakeholders at the time this

[27] Supply curves developed from the Conservation Potential Assessment were adjusted by allowing selection of up to 2% of 2011 actual sales from 2011. After discretionary resources were exhausted, annual opportunities decrease significantly, with remaining resources coming from equipment upgrades and new construction.

case was being defined during the public process that there is no support for the accelerated ramp rates and measure costs, PacifiCorp chose not to select portfolio C-15 with energy efficiency targets that may not be deliverable.[28]

Contrary to CUB's comments that PacifiCorp did not prioritize portfolio C15 in its 2013 IRP, PacifiCorp did in fact recognize the potential benefits of this scenario by targeting specific actions in Action Item 7a of the 2013 IRP Action Plan to accelerate DSM resource acquisition. This was done by stating Class 2 DSM targets using an upper range based on case C15 results, and then identifying specific actions that would be accelerated forward in time. Moreover, CUB's assertion that it is unknown how accelerated DSM would affect FOTs is simply not factual. PacifiCorp communicated through its public input meetings, through technical workshops, and at the October 28, 2013 special public meeting that the top performing portfolios are primarily comprised of energy efficiency resources and DSM resources. Consequently, additional energy efficiency resource acquisition in the near-term would reduce FOT resources, and vice-versa. Further, PacifiCorp notes that all resource portfolios are published in Appendix K, Volume II of the 2013 IRP so that parties can explicitly see how resource selections differ among each case.

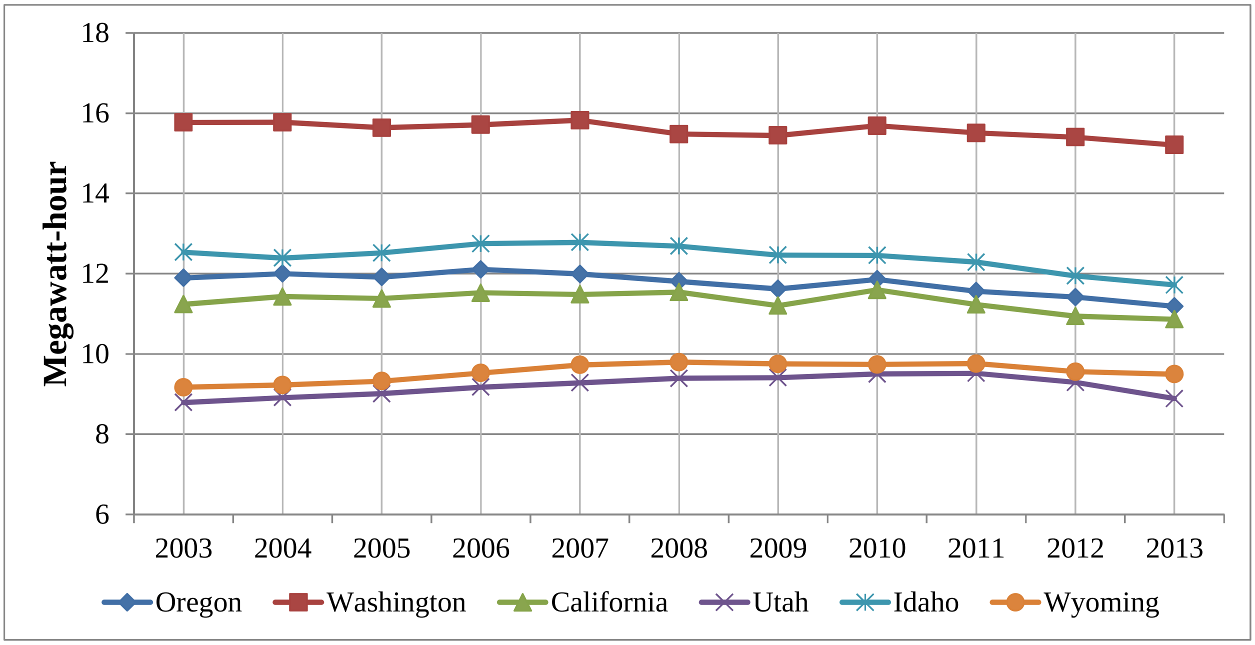
PacifiCorp also disagrees with CUB's comparative analysis of energy efficiency implementation in Oregon as compared to other states. To support its conclusions, CUB provides a figure showing the change in average residential usage since 1990, and notes declining residential usage in Oregon as compared to the other states.[29] CUB's conclusions drawn from this figure are misleading. First, the information used by CUB is not weather

[28] In Action Item 7a of the 2013 IRP Action Plan, the Company commits to test assumptions for accelerated acquisition of DSM resources in the 2014 Conservation Potential Study.
[29] Opening Comments of the Citizen's Utility Board of Oregon at page 5 Figure 1.

normalized, and therefore it does not accurately reflect average changes in usage that may be attributed to energy efficiency improvements. Second, since 2011 all PacifiCorp states have declining average use per customer, with Utah realizing a 2.8 percent decline in 2012 and forecast 2.1 percent decline in 2013. Third, since 2001 the Company has programmatically had to address an increasing saturation of electric cooling as customers move away from the more traditional and less energy intensive evaporative cooling technologies.

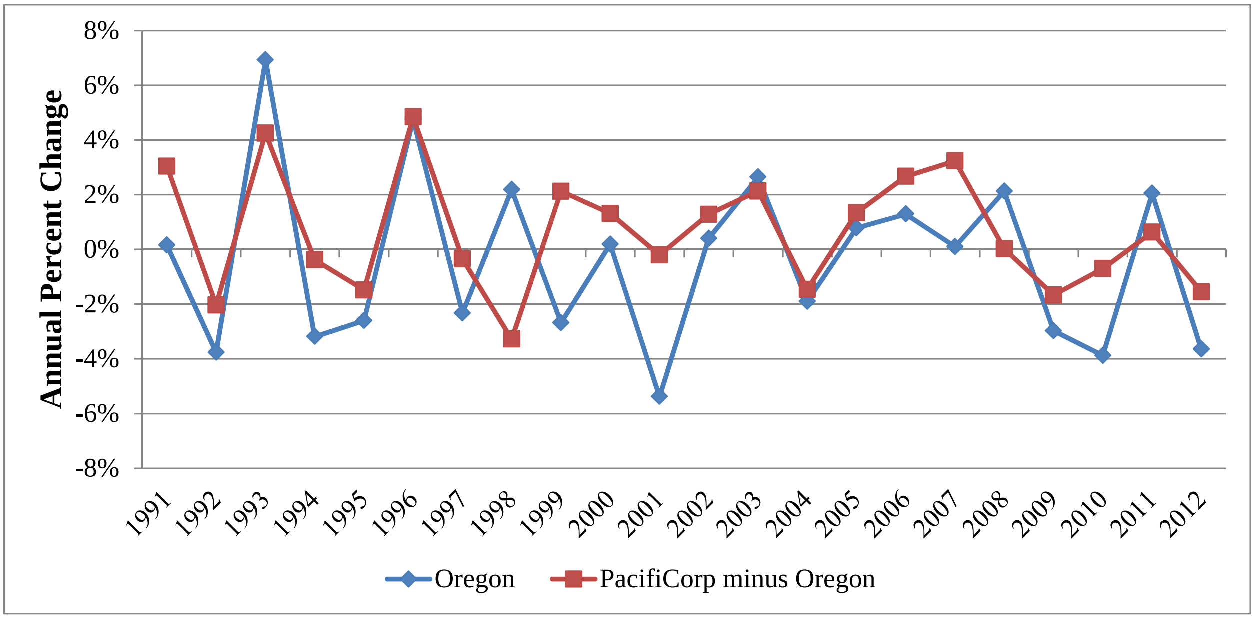
Figure 1 shows the weather normalized average use per customer since 2003. This figure shows that the average use per customer in Utah and Wyoming is less than that of Idaho and the Pacific Power states. Consequently, there is less DSM opportunity per customer (specifically less Class 2, or energy efficiency related opportunities) among the customers in Utah and Wyoming. CUB states that there are "thousands of MWh" that could be saved in Utah if ETO-comparable programs were implemented. This statement is not accurate. Utah is on par with Oregon (if not exceeding Oregon) regarding the adoption of new appliances and energy efficiency improvements to the home, which is evidence that the Company's residential demand-side programs in Utah are as effective as the ETO-comparable programs in Oregon.

Figure 1. Average Use per Residential Customer by State



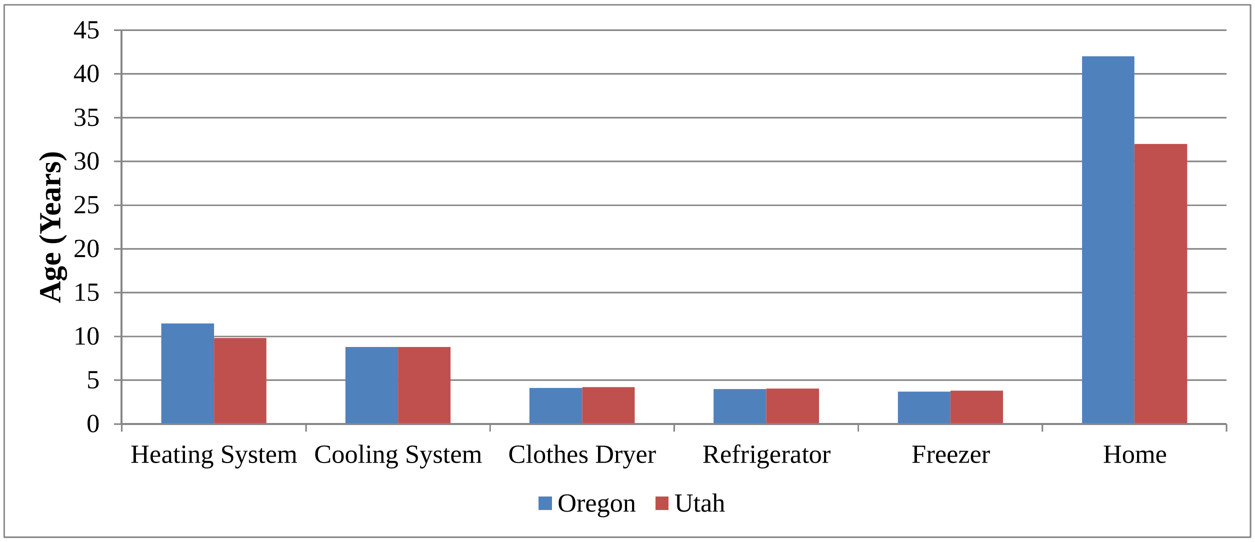
PacifiCorp further notes that if CUB had plotted the annual percent change in average use rather than the cumulative percent change it would have shown a very different picture. The annual percent change in average usage, shown in Figure 2, suggests the difference between Oregon and PacifiCorp's other states is due to recession in 1994, 2001 and 2008, which seem to have hit Oregon harder than PacifiCorp's other states.

Figure 2. Annual Percent Change in Residential Annual Use



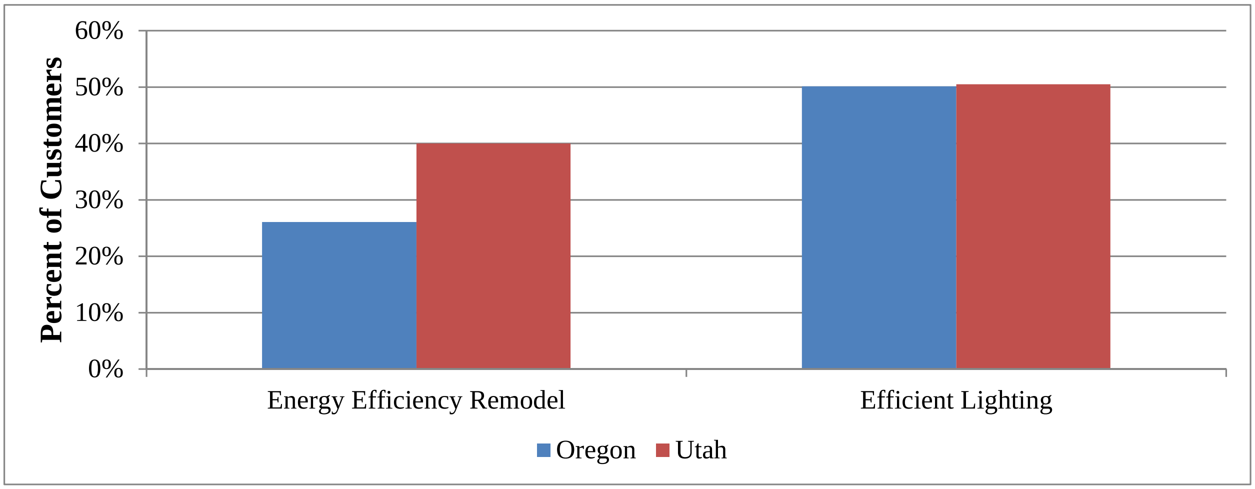
Additional metrics further indicate that CUB's position is unsupported. PacifiCorp recently completed a residential survey in Oregon and Utah in October 2013. The preliminary results from that survey suggest that Utah has the same or higher levels of energy efficient appliances (as indicated by the average age of the appliance) as does Oregon. In addition, the average age of a home in Utah is 10 years newer than in Oregon, indicating that Oregon can realize greater savings from energy efficiency upgrades to the home. Figure 3 shows the results of average age of appliances and homes in Oregon and Utah.

Figure 3. 2013 Residential Survey: Average Age of Appliance and Home



The residential survey results also show that since 2009, Utah customers have invested in energy efficiency upgrades to the home that include ceiling or attic insulation, double or triple glazed windows, and caulking or weather stripping doors and windows at a rate of 40 percent, as compared to 26 percent of Oregon customers. Again, this indicates that the Company's programs are at least as effective, if not more so, in encouraging customers to improve the efficiency of their homes. Figure 4 shows energy efficiency remodel and efficient lighting results for Utah and Oregon.

Figure 4. 2013 Residential Survey: Energy Efficiency Remodel and Efficient Lighting



In support of its opening comments on energy efficiency, CUB also provides a table summarizing DSM as a percentage of loads among all states (using data for the year 2012) and asserts that PacifiCorp is "implementing energy efficiency at a greater rate in Oregon via the ETO than it is in other states using its own in-house programs".[30] In response, PacifiCorp makes the following key observations. First, 2012 was Oregon's high water mark for energy efficiency acquisition, which was influenced by a large 2012 data center project. Highlighting this effect, ETO's 2013 forecasted savings projections are between 168,000 MWh and 186,000 MWh, a decrease of 12 to 20 percent from its 2012 results. Moreover, ETO is not projected to continue to acquire at this level throughout the 20-year planning period. PacifiCorp does not intend to diminish ETO's accomplishments, only to point out that sustainable acquisition at this rate is challenging and not indicative of future trends. Second, metrics such as "kWh savings as a percent of load" are not an absolute measure of demand side program performance and not indicative of a state's commitment to DSM resources. This metric ignores the following:

[30] Opening Comments of the Citizen's Utility Board of Oregon at page 3 and page 4, Table 1.

- Load management investments such as those being made in Idaho and Utah, where the Company, working with those states and our customers, have 329 MW of irrigation and air conditioning load control resources under management in addition to roughly 300 MW of interruptible load under contract.
- PacifiCorp has several extremely large and sophisticated business customers whose loads are counted in the "savings as a percent of load" calculation despite not needing the assistance of or participating in the Company's DSM programs. Due to their energy intensity, their motivation to conserve is directly tied to their bottom-line. While they routinely pursue efficiency projects, the savings are not accounted for in the metric.
- Some utilities, Bonneville Power Administration (BPA), and the ETO (in Oregon, Washington, Idaho, and Montana) claim program savings from initiatives run, tracked and reported by the NEEA that are derived from tracking the adoption of energy efficiency technologies and practices beyond a prescribed or expected adoption rate. Despite similar market adoption occurring in PacifiCorp's other states, only in Washington does PacifiCorp account for these saving due to a lack of similar entities, such as NEEA, to track and help utilities/others identify savings from market transformation not directly attributed to utility/others programs.
- Some DSM programs, like Oregon's, report co-generation project savings and solar water heater savings in energy efficiency savings results. PacifiCorp views savings from these projects as supply-side resources and does not report savings from these sources as DSM savings in other states.

- Not all states and programs report the same kWh per specific measure installed, which makes an apples-to-apples comparison for the same level of activity difficult.
- Despite the adoption rate and market readiness of some states, not all states have the same opportunity to pursue cost-effective savings. For example, the average use per residential customer in Oregon is 11,000 kWh per year, whereas the average use per residential customer in Utah and Wyoming is between 9,000 and 9,500 kWh per year (14-18 percent less than the average usage in Oregon).

Coal Investment Analysis

CUB claims that the IRP has not systematically looked at "the Company's coal fleet in order to identify how coal plants would operate in a world with climate regulation." CUB notes the IRP did not analyze EPA's re-proposed FIP for Wyoming coal units and EPA's proposed regulation of carbon emissions from existing plants. CUB further asserts that PacifiCorp assumed the economic life of environmental investments are inconsistent with the lives of the plants, and states that if this were not the case, the Company would likely conclude investing in less pollution control would be the more cost-effective option. Finally, CUB claims that PacifiCorp's "phase-out" analysis performed for Jim Bridger 3 and 4 was flawed due to misapplication of EPA's cost effectiveness test. CUB recommends that Hunter 1, Jim Bridger 3, and Jim Bridger 4 environmental compliance investments not be acknowledged.

PacifiCorp disagrees with CUB's claims. PacifiCorp analyzed environmental investments required to meet known and prospective compliance obligations across PacifiCorp's existing coal fleet in the portfolio development process. PacifiCorp generated 94 core case resource portfolios, and 71 of these portfolios (over 75 percent) assumed a range of future CO_2 emissions prices recognizing that there is potential for future climate regulation. Similarly, PacifiCorp considered a range of different CO_2 price assumptions in its analysis of specific coal unit investments analyzed within Confidential Volume III of the 2013 IRP. Moreover, as summarized in PacifiCorp's discussion of environmental investment and CO_2 prices above, the CO_2 assumptions applied in the 2013 IRP remain reasonable even when reviewed in the context of EPA's proposed regulation of carbon emissions from existing natural gas and coal resources.

In response to CUB's comments that PacifiCorp did not analyze a wide enough range of potential regional haze compliance requirements based on EPA's re-proposed FIP, the Company reiterates that EPA's requirements have not yet been finalized and restates that, as proposed, EPA's requirements have no bearing on the environmental investments identified in the 2013 IRP Action Plan. In addition and as discussed above, PacifiCorp is proposing a new planning and review process in Oregon that would allow parties to review the Company's analysis of coal unit investments as final state and federal requirements are known and before investment decisions are made.

In reply to CUB's assertion that PacifiCorp has been inconsistent in its assessments of future environmental compliance investments when considering the remaining depreciable lives of the assessed resources, PacifiCorp notes that it is unclear which specific analyses in the 2013 IRP were allegedly performed using inconsistent life of asset inputs. Nonetheless, PacifiCorp clarifies that for the major environmental retrofits for which the Company is seeking acknowledgement in this IRP (Hunter Unit 1, Jim Bridger Units 3 and 4, and Naughton Unit 3), the Company's economic analyses have appropriately applied the remaining depreciable lives referenced in Table 2 of CUB's opening comments.[31] PacifiCorp further clarifies that in none of its IRP modeling did it assumed the installation of an environmental control extends the life of a coal unit.

PacifiCorp further emphasizes that in the environmental compliance realm, EPA does utilize a 20-year assessment period for retrofit emissions control equipment cost effectiveness calculations unless the affected resource has firmly committed to an earlier retirement date. In fact, in the Company's recent public comments submitted in EPA's Wyoming Regional Haze FIP docket, the Company specifically addresses this issue as it pertains to EPA's pending decision-making on Naughton 1 and 2 and Dave Johnston 3. In its comments, PacifiCorp specifically advises EPA that the remaining depreciable lives for those units are less than 20 years and that EPA's assessment of cost effectiveness of available retrofit controls must consider those shorter lives. In general, CUB's arguments regarding perceived flaws in the Company's assessment of remaining depreciable life of assets appears to be focused on units that may ultimately be affected by EPA's final action on the Wyoming Regional Haze FIP, concerns that the Company has already addressed in its public comments in that docket that are not related to any Action Plan items in this IRP.

CUB also takes issue with the Company's assessment and application of hypothetical shut-down dates for Jim Bridger 3 and 4 in the "phase-out" scenario developed to respond to previous requests from CUB to include this type of analysis in the Company's IRP filings. In particular, CUB argues that in determining a hypothetical cost-effectiveness criterion, the Company's $6,000 per ton threshold is not supportable. CUB goes on to argue, that the issue

[31] Opening Comments of the Citizen's Utility Board of Oregon at page 10, Table 2.

for the EPA is not the cost-effectiveness of an SCR, but rather the cost-effectiveness of the comparative control technologies that the EPA considers candidates for BART.

PacifiCorp has been very clear throughout the 2013 IRP process that any attempt to establish a definitive cost per ton threshold that would change the EPA's determination that an SCR is cost effective for a BART-eligible unit is tenuous at best. There is very little (if any), evidence in recent EPA Regional Haze actions across the U.S. that any definitive or consistently applied cost per ton threshold is being utilized by the EPA when determining that SCR is BART for given units. To spend time arguing that any specific cost-effectiveness criteria is actually identifiable and applicable to any given hypothetical "phase-out" scenario is speculative. The Company has focused on developing a "phase-out" scenario that is plausible.

CUB's ultimate conclusion in its argument regarding development and results of the Company's phase-out scenario analysis appears to be that it would prefer to have seen a "phase-out" timeline of 2023 and 2024 for Jim Bridger 3 and 4, in lieu of 2020 and 2021. The Company is amenable to running this alternative "phase-out" scenario, and in fact, received a recent data request from Staff to perform this type of analysis.

CUB goes on to argue that "EPA cannot give PacifiCorp credit for installing the LNB with over-fire air and measure BART from that point forward (making the SCR an incremental addition) because it would allow companies to avoid the best available retrofit technology by making installation less than the best available in order to preempt EPA from requiring the best available." While this argument focuses on issues being addressed in the ongoing Wyoming Regional Haze FIP docket, and not on items specifically identified for acknowledgement in this IRP docket, the Company disagrees with CUB's (and EPA's) position in this regard as it pertains to the Company's timely implementation of its compliance obligations under Wyoming Regional Haze SIP. Again, PacifiCorp has submitted extensive comments on this topic in the Wyoming Regional Haze FIP docket. In general, the Regional Haze rules are very clear about the five factors that EPA must consider when assessing BART controls for individual units when establishing a FIP. One of the five factors that must be considered is the existing controls installed on the unit. The Company's position is that EPA's untimely action on Wyoming's Regional Haze SIP does not allow EPA to ignore existing controls as required by statute.

On balance, the Company appreciates CUB's comments regarding the importance of considering appropriate BART technologies and the remaining useful life of affected resources, because these comments are consistent with the Company's comments submitted in the Wyoming Regional Haze FIP docket. However, these comments have no bearing on the action items identified in the IRP docket for Hunter 1, Jim Bridger 3 and 4, nor the natural gas conversion alternative for Naughton 3 (assuming EPA ultimately approves that Regional Haze compliance approach). PacifiCorp therefore requests that the Commission reject CUB's recommendation to not acknowledge the action items in the 2013 IRP related to these investments.

Transmission

CUB raises concerns with PacifiCorp's System Operational and Reliability Benefits Tool (SBT), and specifically comments that the "Customer and Regulatory Benefits" category is tied to an assumed catastrophic failure. CUB states that the SBT should be subject to further scrutiny and stakeholder input before it can be relied upon to calculate benefits of transmission investments.

In response to Commission feedback on the 2011 IRP, PacifiCorp developed the SBT for identifying and quantifying transmission benefits not captured using traditional IRP analysis tools. In July 2013, PacifiCorp started its efforts to establish an SBT stakeholder workgroup consistent with Action Item 9a in PacifiCorp's 2013 IRP. The Company scheduled workshops with the SBT workgroup to further review the SBT and in preparation for the 2015 IRP, obtain feedback to continue to refine the SBT for future analysis of Energy Gateway segments. The SBT workgroup has met roughly once every month beginning in August 2013 and concluding in November 2013. Through this process the Company has continued to address stakeholder questions and concerns regarding the need to better understand the calculations and assumptions of the SBT benefit categories and in particular around the Customer and Regulatory benefit category.

Specifically, CUB expressed concern over what it referred to as a "binary approach" to calculating the benefit because the calculation assumes every customer in Wyoming, Utah and Idaho has an outage once over a 20 year period without the investment in Segment D, Windstar to Populus. The Company discussed the calculation and assumptions through the SBT workgroup workshop process and, in consideration of feedback received through that forum, committed to separate the Customer and Regulatory benefit category so this benefit component (the Customer benefit) is not part of the cost-to-benefit ratio calculation of the SBT going forward. In addition, PacifiCorp is considering feedback to incorporate a range of benefits for this category and to collect more detailed outage impact data from its large industrial customers. CUB stated at the Commission's October 28, 2013 special public meeting that this effectively resolves its concerns.

6. NWEC OPENING COMMENTS

Energy Efficiency

NWEC comments that the C15 portfolio, which assumes accelerated acquisition of DSM resources, is the least cost least risk portfolio. NWEC further asserts that PacifiCorp's 2013 IRP does not explain why specific assumptions used to obtain accelerated DSM resources are unreasonable. NWEC also states that the Company has not committed to accelerated DSM targets in its action plan. In its comments, NWEC identifies three action items from the 2011 IRP that were either not implemented or delayed. These relate to action items for special contracts customers in Utah and Idaho, a system-wide RFP (excluding Oregon) for specific direct install and other direct distribution programs for residential and commercial sectors, and a study of production efficiency opportunities at generating facilities. NWEC further claims that cost effective DSM resources outside of Oregon are underestimated, noting updates in technical potential from the 2011 to 2013 IRP are different for Oregon as compared to other states, and noting differences in selection of DSM resources under the accelerated DSM scenario for Oregon as compared to other states.

In response to NWEC's comments on the C15 portfolio as the least cost portfolio, PacifiCorp refers to its response to energy efficiency comments provided by CUB.

In response to NWEC's comments on the direct install action item from the 2011 IRP, PacifiCorp refers to its response to Staff's comments from the October 28, 2013 special public meeting.

Regarding NWEC's comments on the 2011 IRP action item addressing Special Contract customers, PacifiCorp notes that this action plan item was intended to help accelerate resource acquisition in advance of the 2016 resource need identified in the 2011

IRP. Even though PacifiCorp terminated the RFP for a 2016 resource in response to an updated Needs Assessment, the Company met with its Utah DSM Steering Committee to discuss the most appropriate way to engage this group of customers on energy efficiency. The recommendation was for the Company to work directly with its Special Contract customers, rather than through a regulatory process, to find ways to assist them in further improving the efficiency at their facilities. Currently these customers contribute over 300 MW of interruptible load to PacifiCorp's system. As explained on page 259 of the 2013 IRP, the Company intends to have individual discussions with each of its Special Contract customers on how it might work more closely together on energy efficiency in a manner similar to our partnership on load management during the next round of contract negotiations.

In response to NWEC's comments on the production efficiency 2011 IRP action item, PacifiCorp notes that production efficiency studies were conducted consistent with requirements of the Washington I-937 Production Efficiency Measure. These studies identified categories of cost effective production efficiency opportunities. Due to challenges in applying these results to PacifiCorp's system as a whole and in establishing regulatory recovery assumptions for estimated capital expenditures among state jurisdictions, production efficiency resource opportunities were not modeled in the 2013 IRP. Action Item 6a in the 2013 IRP identifies PacifiCorp's plans for overcoming these challenges for the 2015 IRP planning cycle.

In response to NWEC's comments that DSM resources outside of Oregon are underestimated, PacifiCorp notes that the resource potential estimates from Oregon are based on a potential study commissioned by the ETO. Consequently, it is uncertain why the change in resource potential in Oregon from the prior study to the current study differs when compared to changes in resource potential between the prior study and the current study among non-Oregon states. The Conservation Potential Assessment commissioned by the Company provides an explanation, beginning on page 87 in Volume I, of the decline found across PacifiCorp's non-Oregon states.[32] A comparable explanation is not readily available for the study commissioned by the ETO, which showed a 13 percent decline in potential as compared to its prior study.

In the Company's Conservation Potential Study, the independent consultant (the Cadmus Group Inc., in collaboration with Nexant, Inc.) explains that much of the decrease in non-Oregon states is the result of changes in the Company's long-term forecasted baseline sales, which were greater in the Rocky Mountain Power states (Utah, Wyoming and Idaho) than the non-Oregon Pacific Power States (Washington and California). Sales in Pacific Power's non-Oregon territory decreased by 12 percent, compared to Rocky Mountain Power's territory, which decreased by 27 percent. The commercial sector saw the most significant decrease in projected sales at 36 percent. Residential loads decreased by 28 percent, and industrial decreased by 16 percent (with minimal load changes occurring for street lighting and irrigation). Other factors noted for the decline included:

- Accounting for newly enacted codes and standards within the planning period;
- Adjusting for actual and projected DSM program accomplishments from 2010-2012;
- Incorporating adjustments to measure savings based on recent evaluation results, including data available from the Regional Technical Form; and
- Applying 2011 customer information to determine segmentation.

[32] The Conservation Potential Assessment is available via the following link: http://www.pacificorp.com/es/dsm.html

Jurisdictional differences such as sales by sector, building stock characteristics, state energy codes, and the timing of when studies are completed are all likely to produce different results between studies, whether completed by the same or different consultant.

In response to NWEC's observations on PacifiCorp's assumed cost adjustments and the selection of DSM resources under the accelerated DSM scenario for Oregon as compared to other states, the Company notes that its adjustments to resource costs for case C15 were modest and most likely under-state what will be required to double or nearly double the rate at which DSM resources are currently being acquired. The adjustments assumed that it would require a doubling of program administration costs and that 100 percent of the incremental cost between standard and high efficiency measures need to be paid, at a minimum, to garner a higher level of customer participation. Since the resources were already priced from a Total Resource Cost perspective in all states except Utah, where they were priced from a Utility Cost perspective, only the resource costs in Utah were adjusted to reflect 100 percent of incremental cost. It is likely that if the Company were to have to pay customers to take action they otherwise might not be inclined to take within the accelerated timeframe desired, the Company may have to pay above incremental costs. Such cost adjustments were not made in developing the high level assumptions for the accelerated DSM inputs applied in developing the C15 portfolio.

Finally, NWEC's assertion that Oregon must already be planning to acquire all available cost-effective conservation on the basis no additional resources were selected in Oregon for case C15 is unreasonable. The reason no additional conservation was selected in Oregon versus other states is explained by the manner in which the ETO constructed their accelerated supply curves. The ETO preserved their resource deployment schedule (ramp rates) bringing forth only more expensive resources for the model to select. The Company on the other hand removed all ramp rates and allowed less expensive resources previously found in future years to be available for the model to select. When the accelerated DSM assumptions were applied in the model, it chose not to select the higher cost resources brought forth from the ETO data and chose to select the resources made available in the non-Oregon states that were accelerated.

Coal Resources

NWEC comments that the Company's coal analysis falls short because base case CO_2 prices are too low and because requirements for future environmental regulations were underestimated. Specifically, NWEC references President Obama's Climate Action Plan as evidence to support a recommendation that the Commission give more careful consideration to high CO_2 price scenarios. NWEC further states that the IRP did not analyze EPA's re-proposed FIP for Wyoming coal units. NWEC recommends the Commission require analysis using a broader range of CO_2 price assumptions and analysis of more stringent regional haze requirements prior to acknowledging any coal plant upgrades in the action plan.

In response, PacifiCorp refers to its previous discussion of these issues in these comments.

Load Control and Demand Response

NWEC claims load control and demand response are undervalued in PacifiCorp's 2013 IRP, noting that no Class 1 DSM programs were added despite 2011 IRP action items seeking these types of resources. NWEC recommends "the Commission encourage the Company to increase the amount and sophistication of its overall analysis regarding demand response and other load control tools in the next IRP." NWEC further states that contrary to

2011 IRP action items, there is no evidence that plug-in electric vehicles and smart grid technologies were included in the 2013 IRP analysis.

As included in PacifiCorp's previous responses to DSM-related issues, PacifiCorp disagrees with NWEC's rationale in asserting the absence of Class 1 DSM resources in the preferred portfolio indicates that Class 1 DSM programs are undervalued in the 2013 IRP. PacifiCorp reiterates that with reduced loads, the need for new resources is greatly reduced as compared to the 2011 IRP. Over the period 2014 through 2020, PacifiCorp's average system capacity position before any new resource additions exceeds 1,300 MW longer in the 2013 IRP as compared to the 2011 IRP. Class 1 DSM resources do not surface in the 2013 IRP preferred portfolio, or any of the top performing resource portfolios, because the resource need has been greatly reduced. PacifiCorp already employs a sophisticated modeling framework that includes a broad range of both supply side and demand side resource alternatives in the portfolio development process. It is not clear based on NWEC's opening comments how it recommends that the Company improve its modeling of demand response and other load control resources in future IRPs.

In response to NWEC's comments regarding plug-in electric vehicles and smart grid technologies, PacifiCorp clarifies that there is no 2011 IRP action item to include these resources in the 2013 IRP analysis. Action item 8 from the 2011 IRP states that the Company would incorporate these technologies as a discussion topic for the next IRP. PacifiCorp included smart grid as a discussion topic during the pre-filing public input process by hosting a smart grid discussion at its December 14, 2012 stakeholder conference call. While plug-in vehicles were discussed among stakeholders during the public input process, PacifiCorp did not include a specific plug-in vehicle agenda item at a public input meeting as priorities were shifted to complete the extensive modeling effort required for the 2013 IRP.

Renewable Resources

NWEC notes that there are fewer renewable resources in the preferred portfolio than in the previous IRP, disagrees with PacifiCorp's decision to comply with Washington's RPS with unbundled renewable energy credits (RECs), and asserts PacifiCorp has not modeled the risk benefits of physical compliance. NWEC states the Commission should not acknowledge the Company's plan to meet Washington RPS requirements with unbundled RECs. NWEC further claims that costs for solar PV resources are too high and that costs will continue to decline into the future. Finally, NWEC asserts that PacifiCorp's IRP modeling framework does not capture diversity and risk value of clean energy resources and recommends the Commission urge the Company to "review and improve its methodology for including natural gas price uncertainty and risk in IRP modeling in the next IRP."

In the development of the preferred portfolio, PacifiCorp evaluated a baseline of renewable resources required to meet the RPS requirements in Oregon, Washington, and California. As part of the final selection process, PacifiCorp selected a Preferred Portfolio that relies on the use of unbundled RECs to comply with Washington state RPS requirements because it is least cost, least risk alternative. PacifiCorp disagrees with NWEC's position that the Company did not model risk benefits of physical compliance. To the contrary, PacifiCorp informed its determination of the preferred portfolio by completing both cost and risk analyses that quantify how the preferred portfolio (assuming Washington RPS compliance is achieved with REC's) compares to an alternative portfolio containing wind resources for the sole purpose of meeting Washington state RPS requirements (physical compliance).[33] PacifiCorp therefore disagrees with NWEC's acknowledgement recommendation regarding the Company's action item for Washington RPS compliance.

Regarding NWEC's comments on solar costs for distributed generation, PacifiCorp notes that in developing the 2013 IRP, it used inputs for the market potential and the solar PV costs provided by the Cadmus Group, an independent consultant. The reports used to create these inputs were reviewed by stakeholders, and stakeholder input was used to test and refine the Cadmus assumptions. Although consensus on these assumptions was not achieved, the numbers provided were rational estimates of both the market potential and solar PV costs based on the best information available.

NWEC summarizes data from the Lawrence Berkeley National Laboratory (LBNL) as evidence that PacifiCorp's cost assumptions are overstated and further suggests that the cost for rooftop solar applications will continue to decline over the next 20 years. PacifiCorp notes that there is also evidence that component prices are leveling off. In its second quarter 2013 U.S. Solar Market Insight Report, the Solar Energy Industries Association (SEIA) reports that pricing for polysilicon and PV components increased for the first time in more than two years given strong demand in the global market and a consolidated supply chain.[34] SEIA also reports that module pricing has already climbed further in the third quarter of 2013. At this point it is unclear if recent price decline observations are a sustainable trend or a market aberration based on oversupply that will moderate over time.

[33] PacifiCorp 2013 IRP, Volume I, Chapter 8, pp. 224 – 226.
[34] "U.S. Solar Market Insight Report Q2 2013 Executive Summary", Greentech Media, Inc. and Solar Energy Industries Association, 2013.

The Company acknowledges that the environment impacting distributed solar PV is rapidly transforming. PacifiCorp will continue to reassess its solar resource cost assumptions, as is done for all resource alternatives, through its ongoing planning efforts. As costs are updated for the 2015 IRP, PacifiCorp will review the most recent market data available and will review results from recently initiated programs, like the Utah Solar Incentive Program, in assessing cost assumptions in its planning efforts.

PacifiCorp disagrees with NWEC's assertion that the IRP modeling framework does not capture the risk mitigation benefits of clean energy resources. In contrast to NWEC's comments, PacifiCorp's IRP modeling approach accounts for both natural gas and electricity price volatility in its analysis of resource portfolios.[35] Moreover, PacifiCorp evaluates scenario risks, by deploying its stochastic model among a range of CO_2 price scenarios that capture the impact of CO_2 costs on natural gas price projections. Volume I, Chapter 7 of the 2013 IRP describes the modeling approach. Through its Monte Carlo production cost modeling and CO_2 price scenario modeling, PacifiCorp explicitly captures both fuel and emission risk mitigation benefits of clean energy resources. These benefits are captured in the portfolio cost and portfolio risk metrics that are used to inform selection of the preferred portfolio.

Transmission

NWEC commends PacifiCorp for expanding its analysis of transmission investments in the 2013 IRP. However, NWEC claims that PacifiCorp's transmission analysis does not fully analyze transmission needs for scenarios in which coal plants are phased out more quickly. NWEC recommends the Commission encourage the Company to consider a broader

[35] Loads, hydro energy availability, and thermal unit availability are also evaluated as stochastic variables subject to Monte Carlo random sampling.

range of supply scenarios in its future transmission analysis. NWEC also comments that PacifiCorp's SBT is promising because it captures benefits that system-wide tools cannot measure; however, NWEC further states that the tool is in the preliminary stages of development and needs further refinement. Specifically, NWEC states that it is not clear how the SBT should be used to assess whether the Sigurd to Red Butte or Windstar to Populus projects should go forward. Finally, NWEC notes that the "Customer and Regulatory Benefits" category is not sufficiently documented and that it should not be included in the SBT at this time.

PacifiCorp does not agree with NWEC's claims that the 2013 IRP does not analyze transmission needs for a scenario in which existing coal plants are phased out more quickly. Modeling of alternative transmission investment scenarios within the portfolio development process is one of the significant modeling improvements implemented for the 2013 IRP. This modeling approach ensures that portfolios developed under a given set of inputs for commodity prices, environmental policy, renewable portfolio standards, and other assumptions could be directly compared across five different transmission investment scenarios. There were several portfolios generated in the 2013 IRP resulting in an early phase out of existing coal units. This includes portfolios developed under cases C4, C5, C8, C9, C14, and C18.[36] Portfolios for each of these cases were developed across each of the five transmission investment scenarios, allowing for a comparative analysis of portfolio costs. PacifiCorp summarized all portfolios, including those listed above that resulted in an early phase out of existing coal units, among each of the transmission investment scenarios in figures in Chapter 8, Volume I beginning at page 207 of the 2013 IRP.

[36] Portfolio results are summarized in Chapter 8, Volume I, Figures 8.1 through 8.5, and all resource portfolios are provided in Appendix K, Volume II.

In much the same way that the 2013 IRP modeling approach allows for comparison of portfolios that have early coal unit retirements among different transmission scenarios, the construct of scenarios also allows for a comparison of how transmission investments affect renewable resources, both with and without RPS requirements. Those portfolios modeled both with and without RPS requirements were analyzed across all five transmission scenarios. For instance, a comparison of these portfolios between Energy Gateway scenarios two and three show how renewable resource selections and portfolio costs are affected when Energy Gateway Segment E (Populus to Hemmingway, across central Idaho) and Segment H (Boardman to Hemmingway) are included as an incremental transmission investment.

PacifiCorp continues to explore opportunities to partner on transmission development where it is beneficial to PacifiCorp's customers and satisfies the needs of PacifiCorp's customers, including wholesale customers such as BPA. PacifiCorp further notes that it had a memorandum of understanding with Portland General Electric Company (PGE) for the development of Cascade Crossing that terminated by its own terms. PacifiCorp continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue a Cascade Crossing solution with BPA. However, because PGE has decided to end discussions with BPA and instead pursue other options, PacifiCorp will not be actively pursuing this development opportunity or performing analysis on a project opportunity that is no longer available.[37] That said, PacifiCorp will continue to look to partner with third parties on transmission development as opportunities arise.

Regarding the SBT, PacifiCorp continues to review and consider feedback collected from participants throughout the SBT workgroup workshop process. The Customer and

[37] See Action Item 9b of the 2013 IRP, "Segment H, Cascade Crossing, complete benefits analysis in 2013."

Regulatory benefit category was "to be determined" for Sigurd to Red Butte because not all SBT categories are used or applicable for every transmission investment. Furthermore, PacifiCorp clarifies that it did not use the SBT to justify the Sigurd to Red Butte transmission project. Rather, the Company used this project as an illustrative example of how the tool could be applied to a new transmission project. Key drivers of the Sigurd to Red Butte transmission project include compliance with the reliability standards of the North American Electric Reliability Corporation (NERC) and regional standards and criteria for system operation of the WECC, reliably serving load in southwestern Utah including during transmission line outages or major equipment contingencies, meeting transmission service obligations, and improved access to existing and new generation resources.

7. RNP OPENING COMMENTS

IRP Preferred Portfolio

RNP comments that acknowledgment of PacifiCorp's preferred portfolio includes investments in coal, "side-steps" demand side management resources, and delays acquisition of new clean energy resources. RNP claims there has been a shift in federal energy policy and that given President Obama's announcement on pending regulations, CO_2 prices will begin sooner and will be higher than what has been assumed in the 2013 IRP. RNP further asserts that absent analysis of EPA's re-proposed FIP for Wyoming coal units, the 2013 IRP action plan does not reflect the true cost for retrofitting coal units. RNP recommends the Commission review the action plan in the context of high CO_2 price assumptions.

In response, PacifiCorp relies on the discussion of coal plant investment and on CO_2 cost included above. PacifiCorp reiterates that EPA's re-proposed FIP for Wyoming coal units does not affect action items in the 2013 IRP Action Plan and that these requirements have not yet been finalized.

Energy Efficiency

RNP comments that the highest performing portfolio includes accelerated DSM, and that despite these results, PacifiCorp is choosing a plan that does not accelerate acquisition of these resources.

In response, PacifiCorp refers to its discussion of DSM and energy efficiency above.

Renewable Resource Capacity Value

RNP claims that PacifiCorp's assumed capacity contribution assumptions for renewable resources are not accurate, noting that the performance of candidate portfolios is measured by a resource's ability to meet capacity for the entire year. RNP recommends "the Commission ask PacifiCorp to provide a scenario in the next IRP that measures the capacity value of renewables using the ELCC methodology".

PacifiCorp's capacity contribution assumptions are accurately calculated and appropriate as applied in the IRP modeling framework. When developing resource portfolios in the 2013 IRP, resource adequacy is measured by achieving a portfolio that meets the coincident system peak load including a 13 percent planning reserve margin. In effect, resource adequacy is measured at the time of peak load. Evaluating the capacity contribution of wind and solar resources during summer peak load hours aligns the peak contribution input assumption with this resource adequacy planning criteria. Once portfolios are developed in System Optimizer, they are analyzed in Monte Carlo production cost simulations, where the energy that is produced by wind and solar resources in the portfolio *among all hours* contributes to reducing energy not served (a measure of reliability) as load, hydro availability, and thermal unit availability stochastic variables are sampled. The "energy not served" results of the Monte Carlo production cost simulation are considered in determining the preferred portfolio and in this way the contribution of wind and solar resources to reducing "energy not served" metrics, among all hours of the year, are factored into the determination of the preferred portfolio. Nonetheless, as stated in response to Staff's opening comments on this issue, PacifiCorp will consider Staff's recommendation to compare the capacity contribution of wind and solar resources between alternative methods.

Wind Capacity Factors

RNP believes PacifiCorp's capacity factor assumptions for west-side wind resources is too low, and further claims PacifiCorp refused to accept third-party, publicly available estimates of improved capacity factors. RNP references a PGE project in Washington as having an expected capacity factor of 37 percent.

PacifiCorp's regional wind capacity factors were based on historical operating data. During the IRP pre-filing process, the Company requested that interested parties submit verifiable capacity factor information. One party responded and as a consequence the capacity factors for Wyoming based resources were adjusted to reflect these higher capacity factors. PacifiCorp further notes that PGE's recently announced project in Washington is not necessarily indicative of capacity factors that might be expected from wind projects in the Pacific Northwest going forward. PGE received 64 bids representing 39 distinct generating projects in its RFP, and the selected project is, presumably, the best alternative among all of these proposals.[38] In fact, PGE continues to assume capacity factors at 32 percent, well below

[38] Portland General Electric News Release: "PGE Reports on RFP Responses for Renewable Generating Resources." November 26, 2012.

those anticipated for the recently announced wind project, in its long term planning efforts.[39] Idaho Power currently assumes a capacity factor of 26 percent in its IRP.[40] PacifiCorp's wind resource capacity factor assumption of 29 percent for the Pacific Northwest is aligned with those being assumed by other regional utilities. For the 2015 IRP, the Company will pursue a similar process as was used in the 2013 IRP to obtain reliable capacity factor estimates that reflect new wind turbine designs for different regions.

Solar and Wind Costs

RNP states that PacifiCorp's solar costs are at odds with industry standards, referencing NWEC's comments on this issue. RNP further comments that PacifiCorp's wind resource costs are high relative to a project recently announced by PGE. RNP recommends PacifiCorp hold notice of meetings with market participants so that stakeholders can cross-reference information. RNP further recommends PacifiCorp develop sensitivities showing how assumptions affect selection of renewable resources.

In response to RNP's comments on solar costs, PacifiCorp refers to its response to NWEC's August 2013 opening comments on this topic. PacifiCorp further notes that its small utility scale solar costs applied in the 2013 IRP are reasonably aligned with bids PacifiCorp received in the 2013 Solar RFP seeking solar resources to meet the Oregon solar capacity mandate goal.

The capital costs developed by the Company for the 2013 IRP supply side resource table in Chapter 6, Volume I for wind resources were based on a wind farm with a nominal capability of 100 MW. The capital costs of wind resources are based on implementation of wind projects in the 2018 timeframe and beyond. Wind resource costs were based on

[39] Portland General Electric IRP Presentation, June 26, 2013.
[40] Idaho Power 2013 Integrated Resource Plan, Appendix C Technical Report, page 89.

information provided by the major original equipment manufacturers at the time the supply side resource table was prepared. Balance of plant costs were based on actual costs incurred on the Company's wind projects. Original equipment manufacturers provided no information to demonstrate that current market conditions for wind turbines are sustainable or indicative of long term pricing for projects implemented in timeframe of 2018 and beyond. In addition, the Company reported capital costs that include owner's costs which include permitting and permitting-related costs, transmission interconnection, generation transmission tie-line, allowance for funds used during construction (AFUDC), project management and surcharges, and capitalized land owner payments. It is unknown to what extent costs reported by others include these costs or additional costs such as asset acquisition costs. Furthermore, it is unknown if some benefit due to economy of scale may be reflected in the lower reported costs (247 megawatts versus 100 megawatts). PacifiCorp acknowledges that future IRPs should continue to take into consideration the energy capture capability associated with then-current wind turbine generator designs; taking into consideration the applicability of a design relative to local and regional wind regimes.

RNP is incorrect "PacifiCorp will only accept proprietary data related to capacity value and prices." This statement is unclear since it is contrary to the Company's process to obtain performance information. In August 2012, the Company issued a Request for Information (RFI) as a means to secure up-to-date and verifiable performance information as a mechanism to inform location and turbine related capacity factors. The RFI states that "PacifiCorp is seeking non-confidential information only" and required that "all information provided to PacifiCorp must be clearly marked as non-confidential". The RFI further states that "[a]ny party submitting information acknowledges that information submitted is not proprietary, nor does it constitute a trade secret of the submitting party." Only one party submitted information in response to this RFI.

Transmission

RNP notes that the scope of transmission analysis was greatly expanded in the 2013 IRP and commends PacifiCorp for its ingenuity in analyzing transmission. RNP notes that while stakeholders expressed concern about the "Customer and Regulatory Benefits" category in the SBT, it recognizes that the tool is in preliminary stages of development. RNP recommends the Commission allow discussion to develop regionally to allow further improvements in the SBT.

In response, PacifiCorp refers to its discussion of transmission-related comments above.

8. ODOE OPENING COMMENTS

ODOE primarily comments on CO_2 price assumptions applied in the 2013 IRP, and contends that PacifiCorp had not satisfied Oregon IRP Guideline 8a, and by extension, does not comply with Guideline 1c. Specifically, ODOE opines that:

- PacifiCorp's base case assumptions are not the most likely scenario;
- PacifiCorp did not analyze the two highest price scenarios in its risk analysis;
- A "governing entity" as used in Guideline 8a includes the 50 states, the U.S. federal government, Canadian provinces, and other democratically-elected sovereign states;
- A single economy-wide price will be higher than the price to achieve the same level of reduction from the power sector alone; and
- EPA will be guided by the social cost of carbon in its emission performance rule making and that this will lead to a carbon price between \$52 and \$76 per ton by 2030.

ODOE further recommends the Commission should "instruct PacifiCorp for the next IRP that the 'upper reaches of credible proposals by governing entities' in Guideline 8a, Order No. 08-339, includes the Oregon goal under ORS 468A.205(1)(c) of achieving 'greenhouse gas levels that are at least 75 percent below 1990 levels' by 2050 as an *economy-wide* goal for the U.S."

ODOE also comments on PacifiCorp's assumptions related to the assumed level of capacity credit among wind and solar resources. ODOE recommends the Commission "should direct PacifiCorp that for the next IRP it should conduct a stochastic assessment of the appropriate capacity credit for solar and wind resources based on unserved energy for all 8,760 hours of the year."

PacifiCorp disagrees with ODOE's claim that PacifiCorp has not satisfied Oregon Guideline 8a, and by extension, Oregon Guideline 1c. PacifiCorp included in its 2013 IRP a review of environmental regulation and legislation in Chapter 3, Volume I. This section of the IRP includes a discussion of federal climate change legislation, noting that the two most prominent proposals have been the Waxman-Markey bill in 2009 and the Kerry-Lieberman bill in 2010.[41] PacifiCorp further provides an overview of EPA regulatory activity related to GHG emissions, addressing new source review (NSR) and prevention of significant deterioration (PSD) permitting programs, EPA guidance on best available control technology (BACT), and EPA's activity on developing performance standards for GHGs. PacifiCorp identifies in Chapter 7, Volume I of the 2013 IRP beginning at page 167 each of its CO_2 price scenarios.

[41] Neither measure was able to accumulate enough support to pass.

In identifying the CO_2 price assumptions applied in the 2013 IRP, PacifiCorp notes its base case is aligned with a price signal that would be required to induce switching from coal to natural gas-fired generation sources. PacifiCorp further communicated to stakeholders in the public input process that it informs its base case CO_2 price assumptions by reviewing the most current third- party forecasts received through subscription services.[42] These third party forecasts take into consideration the current policy environment in developing their assumptions and form the basis for PacifiCorp selection of the expected carbon price scenario.

PacifiCorp further explains that its high CO_2 price scenario reflects regulations that are ramped to more stringent requirements, and notes that the resulting forecast is consistent with the price ceiling identified in the 2010 Kerry-Lieberman bill that was identified in Chapter 3, Volume I as one of the most prominent recent legislative proposals. PacifiCorp also showed how its CO_2 price scenarios compare to the Kerry-Lieberman price ceiling during the public input process.[43] PacifiCorp further notes that both the Waxman-Markey and Kerry-Lieberman bills included cost containment provisions designed to contain cost price volatility, contain costs, or both.

PacifiCorp's 2013 IRP also considered even higher price scenarios in the portfolio development process. These scenarios reflect CO_2 price costs estimated to achieve an 80% reduction in emissions from the U.S. power sector by 2050.[44] These scenarios were

[42] PacifiCorp discussed this approach with stakeholders at the September 24, 2012 public input meeting and shared a graph showing how these third party forecasts compare to the base case and other CO_2 price assumptions applied in the 2013 IRP. This presentation is available via the following link: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_PRMStudy-FPC_09-24-12_ConfCall.pdf

[43] *Ibid.*

[44] Two variants of this scenario were developed – one using base case natural gas price assumptions, and one using high natural gas price assumptions.

developed in response to stakeholder input, which included a specific recommendation targeting at least an 80% reduction in emissions by 2050, when assumptions for the portfolio development process were being developed over the course of four public input meetings held between June 20, 2012 and September 14, 2012. PacifiCorp maintained a record of stakeholder input and documented the Company's response to those recommendations in a Portfolio Development Log, which was reviewed with stakeholders at the September 14, 2012 public input meeting.[45]

In discussions among stakeholders regarding the hard cap scenarios, PacifiCorp described how it would develop the price projections assuming a hard cap applicable to the U.S. power sector. This discussion was rooted in the fact that PacifiCorp does have access to a U.S. power sector modeling tool, but does not have access to an economy-wide U.S. modeling tool. Stakeholders generally found this to be an agreeable method to develop additional scenarios that might yield prices higher than those assumed for the high CO_2 price scenario. Moreover, PacifiCorp disagrees with ODOE's opinion, stated as fact, that an economy-wide price will be higher than the price to achieve the same level of reduction from the power sector alone. While it is possible for an economy-wide regulation to yield higher CO_2 prices, it is not a foregone conclusion. The relationship between a power sector and economy-wide regulation would be influenced by the specific rules of a future regulatory program. For instance, a regulatory construct that allows for the use of cross-sector domestic and international greenhouse offsets could lead to an economy wide CO_2 regulation that

[45] The Portfolio Development Log is posted on PacifiCorp's IRP website: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/2013IRP_PortfolioDevelopmentLog_09-14-12.pdf

yields a lower CO_2 price outcome than an alternative regulation that covers only the power sector of the U.S. economy.

Further, ODOE did not raise its concerns with PacifiCorp's CO_2 price scenarios at the time CO_2 price assumptions were being developed for the 2013 IRP. Based on the Company's review of the Portfolio Development Log, ODOE did not provide the Company with requests for specific cases or requests for alternative CO_2 price assumptions during the public input process.[46] PacifiCorp requests the Commission reject ODOE's recommendation to include a prescriptive requirement for a specific CO_2 price scenario in future IRPs. PacifiCorp believes it is more efficient for the Company to work with its stakeholder group to establish a set of CO_2 price scenarios that represents the "upper reaches of credible proposals by governing entities." As discussed above, the Company was responsive to stakeholder requests received during the public input process in developing the two hard cap scenarios used in the 2013 IRP.

PacifiCorp disagrees with ODOE's opinion that a "governing entity" be defined to include Canadian provinces and other democratically-elected sovereign states. The regulatory structure, legal framework, political and economic objectives, market structures, and other factors that might influence GHG regulation outside of the U.S. limit the applicability of those efforts on regulatory mechanisms that might be applied within the U.S. Inasmuch as regulations outside of the U.S. have influence on the U.S. regulatory approach, this would be captured in reviewing the U.S. regulatory climate as assumptions are reviewed within the recurring IRP cycle. Moreover, as noted above, PacifiCorp has and will continue to welcome stakeholder input through the public process on specific CO_2 price proposals.

[46] *Ibid.*

Notwithstanding the above, should the Commission consider it necessary, PacifiCorp does not object to the Commission defining "governing entity" in the context of Oregon Guideline 8c.

In response to ODOE's opinions on the social cost of carbon, PacifiCorp disagrees that "EPA will be guided by the social cost values" released in May 2013. The social cost of carbon represents a monetized value of future worldwide economic damages associated with a one ton increase in CO_2 emissions in a particular year discounted to the present. The social cost of carbon is not a carbon price to be derived from a future policy. The carbon price associated with a policy that specifies an environmental target is a measure of the marginal cost of abatement. The social cost of carbon is a measure for the marginal benefit of abatement, and is used by federal agencies to assess the tradeoff between the benefits and the costs of a proposed regulation. Moreover, PacifiCorp notes that this is not the only factor federal agencies assess when evaluating the benefits and costs of a proposed regulation.

In response to ODOE's comments regarding the capacity contribution of wind and solar resources, PacifiCorp refers to its response to comments provided by RNP on this topic.

9. ICNU OPENING COMMENTS

Allocation of Costs

ICNU suggests that the 2013 IRP will be used to justify the allocation of higher costs to Oregon customers. Specifically, ICNU states that Oregon customers should not pay for transmission and generation projects that do not benefit the Company's western operations. ICNU is further concerned that Oregon will have to pay for renewable resources mandated by state laws while also paying for nearly all of the Klamath relicensing and potential dam removal costs. ICNU also claims that weak conservation programs in non-Oregon states can influence costs for Oregon customers.

While PacifiCorp appreciates ICNU's comments, the Company notes that the 2013 IRP is used to develop a system-wide least cost, least risk resource plan consistent with the planning guidelines established among its states. In producing its 2013 IRP, the Company ensures its resource plan meets both federal and state laws; however, PacifiCorp reiterates that the IRP and MSP are two distinct and different processes with different goals. The MSP process is concerned with allocating costs among states based on defined allocation methodologies, which is outside the scope of the 2013 IRP. PacifiCorp further responds by referencing its reply to comments on energy efficiency above.

Transmission

ICNU expressed concern that 2013 IRP modeling will be used to justify allocation of higher costs to Oregon customer, and, in particular, costs related to the Sigurd-Red Butte project. ICNU recommends that SBT analysis should review whether any benefits are incremental to the 2013 IRP and how they would flow through to ratepayers. ICNU also asserts that cost savings should also be looked at if the transmission investment is not built and instead relied on conservation, net metering, or cogeneration resources.

PacifiCorp does not agree with ICNU's assertion that 2013 IRP modeling of transmission is used to justify higher transmission costs to Oregon customers. The Company incorporated modeling related to transmission investments, including the Company's Energy Gateway transmission expansion program, as requested by stakeholders through the 2013 IRP process. PacifiCorp not only has the burden of demonstrating the necessity of each of these transmission segments through CPCN proceedings, as applicable, but also has the burden of demonstrating the prudence of these investments to recover the costs in ratemaking proceedings where ICNU and other parties will have the opportunity to participate. As noted above, cost allocation is outside the scope of the 2013 IRP and will be addressed in the MSP process.

It is important to note that Energy Gateway is the overall expansion program and each Energy Gateway segment will be justified individually based on a combination of federal or state regulatory requirements and customer benefits. These could include net power cost savings, compliance with mandatory reliability standard requirements, satisfaction of network customer needs, capital offsets for renewable resource development in low-yield geographic regions, compliance with open access transmission tariff requests or system loss reductions. Each segment continues to be re-evaluated during the Company's annual business plan and IRP cycles to ensure appropriate benefits and timing before moving forward with permitting and construction. Segments could be deferred, modified or not constructed, depending on conditions or alternatives, if analysis shows the need or timing has changed.

In response to ICNU comments on the use of conservation, net metering or cogeneration resources as an alternative to transmission investments, PacifiCorp notes that resource portfolios were developed allowing a wide range of resource alternatives, including conservation, distributed generation and cogeneration resource options. Moreover, PacifiCorp's modeling framework allowed for these resources, and others, to be selected among five different Energy Gateway scenarios. Consequently, portfolio modeling performed in the 2013 IRP under this framework does in fact evaluate how these resources and overall portfolio costs are affected among different transmission expansion scenarios.

<u>Carbon Regulation</u>

ICNU states that it continues to review the parties' comments on carbon regulation and environmental compliance. ICNU urges PacifiCorp to plan for a variety of regulatory outcomes. ICNU notes that carbon tax assumptions have been made in IRPs for years and yet "we appear to be far from any federal carbon tax or regulation."

In response, PacifiCorp notes that it has and will continue to evaluate a range of potential environmental compliance requirements in its IRP process.

10. SIERRA CLUB OPENING COMMENTS

<u>Portfolio Scenarios</u>

Sierra Club classifies resource portfolios developed for the 2013 IRP as having two key sets of differences that yield either limited or extensive coal retirements and portfolios having either no or minimal wind until 2022. Sierra Club notes that neither transmission scenarios nor Regional Haze assumptions materially affect early coal retirements. Rather, Sierra Club observes that commodity price assumptions drive wide endpoints in coal retirement outcomes. Sierra Club asserts PacifiCorp rejects these portfolios on the basis that they do not perform favorably under baseline conditions. Sierra Club also comments that the commodity price scenarios used in the IRP capture only the most extreme cases.

In response, PacifiCorp agrees with Sierra Club's observations that transmission scenarios and Regional Haze assumptions had minimal impact on coal unit early retirement outcomes. As noted by Sierra Club, portfolios with early coal unit retirements occur in those cases where commodity prices (and CO_2 price assumptions) favor alternatives to environmental investments. For instance, portfolios with low natural gas price inputs, high CO_2 prices, and high coal costs produced portfolios with significant early coal unit retirements. When evaluated during the portfolio selection process, these portfolios were high risk and high cost, and were not chosen as the preferred portfolio.

As discussed in response to opening comments provided by ODOE and CUB, PacifiCorp worked with its active and engaged stakeholder group to develop assumptions used to develop resource portfolios in the 2013 IRP. PacifiCorp discussed this topic with stakeholders over the course of four different public input meetings held in 2012. While it is PacifiCorp's goal to be responsive to all stakeholders and all requests, it is not often practical or possible to accommodate all requests. Given these practical limitations, and considering that the IRP considers a broad spectrum of issues beyond coal unit retirements, PacifiCorp could not reasonably complete every combination of natural gas and CO_2 price assumptions as suggested by Sierra Club in its comments. PacifiCorp therefore implemented recommendations from stakeholders to capture "book end" inputs for use in the portfolio development process. PacifiCorp further clarifies that it does in fact model varying combinations of natural gas price and CO_2 price assumptions when performing the detailed financial analysis summarized in Confidential Volume III in support of its coal resource action items in the 2013 IRP Action Plan.

<u>Social Cost of Carbon</u>

Sierra Club states that PacifiCorp's low natural gas, high CO_2 price assumptions are not an "extreme case" when compared against the social cost of carbon recently published by EPA. Sierra Club asserts that EPA's expected rulemaking to establish performance standards for CO_2 emissions may use the social cost of carbon to justify stringent regulations with price impacts above those assumed by the Company. Sierra Club further notes that coal unit retirements occur before the onset of a carbon price. Sierra Club then states that an outcome with substantial early retirements is within the range of reason and that that these portfolios should not be discounted because they do not perform well when analyzed in PaR.

In response to Sierra Club's comments on the social cost of carbon, PacifiCorp refers to its response to ODOEs' comments on this topic. Similarly, PacifiCorp also refers to its previous responses to comments on the CO_2 price assumptions used in the 2013 IRP.

PacifiCorp further notes that it is not surprising to see coal unit retirements occurring before the onset of a carbon price assumption. The System Optimizer model makes resource decisions with full recognition of future costs and benefits that will occur as a consequence of those decisions. Thus, the System Optimizer model recognizes particularly among those scenarios with low natural gas prices, high CO_2 prices, and high coal costs that an early retirement made in advance of a CO_2 policy will avoid *future* CO_2 costs. The model considers the avoidance of these future CO_2 costs when evaluating compliance alternatives that must be implemented before the effective date of the future CO_2 policy. The portfolios from these scenarios are the least cost given the specific input assumptions used for the case, which are effectively "known" by the model with 100 percent certainty over the entire 20-year planning horizon.

<u>Planning and Risk Analysis</u>

Sierra Club states that PacifiCorp's PaR studies used to test the portfolios against uncertainties, by design, are "biased towards the selection of the reference or base case," because the average outcome of the 100 random iterations reflects essentially the outcome from a run with the base assumptions on market prices for power and natural gas. Sierra Club asserts that this results in massive upside risk for gas-heavy portfolios and narrow band of risk for coal-heavy outcomes.

PacifiCorp does not agree with Sierra Club's characterization of the PaR model. The Company, in collaboration with stakeholders participating in the IRP public process, establishes "core case" definitions. Recognizing, a range of uncertainties across many different variables, this entails locking down different combinations of model input assumptions that can yield a range of resource portfolio outcomes. In the context of its IRP, PacifiCorp emphasizes that the product of this step of the process is a collection of resource portfolio alternatives. These portfolios are then analyzed in PaR among a consistent set of scenarios so that the cost and risk of each portfolio can be evaluated on a comparable basis. In its PaR analysis, PacifiCorp evaluates both *stochastic* risk by performing Monte Carlo modeling studies that draw certain variables, such as natural gas prices, from a distribution and CO_2 price *scenario* risk by completing the stochastic analysis among different CO_2 price input assumptions. When Monte Carlo draws are made on natural gas price inputs, and the frequency distribution of those draws is evaluated, by definition, the mean of that natural gas price distribution is representative of the expected price forecast.[47] The distribution further shows price draws that deviate from the mean, which includes extreme, albeit lower probability price outcomes. This construct allows PacifiCorp to evaluate a range of portfolios on a consistent and comparable basis using both expected portfolio costs (the stochastic mean PVRR) and by evaluating the high cost, albeit lower probability outcomes.

PacifiCorp uses 100 Monte Carlo iterations in its stochastic analysis performed using PaR. While the individual draws from the 100 random iterations converge to the expected value for each individual variable (i.e. natural gas prices, electricity prices, load, and outages), the mean of portfolio costs, measured as the PVRR, from the 100 random iterations

[47] This applies to all stochastic variables analyzed in PaR.

is not necessarily the same as would be observed in a deterministic simulation using static inputs for each variable. For example, in a single iteration with a high natural gas price draw, the gas-fired units may be dispatched down or even shut down. In a single iteration with a low natural gas price draw, generation from coal-fired units could be displaced by generation from gas-fired units. The average outcome of these iterations on portfolio costs will not necessarily match the outcome of a single iteration that draws the expected natural gas price value. This is evident considering that the 2013 IRP preferred portfolio, which was produced in the portfolio development process using non-base case commodity price assumptions, was selected as the least cost, least risk portfolio as evaluated using PaR.

Cholla

Based on the observation that Cholla 4 retires in select portfolios, Sierra Club asserts that PacifiCorp must retire Cholla 4.

PacifiCorp has not finalized its analysis of Cholla 4, and consequently, has not made a decision to either invest in the necessary environmental controls required for this facility to continue operating as a coal-fueled plant or to pursue alternatives such as natural gas conversion or early retirement. PacifiCorp also refers to its description of the proposed framework for parties to review an analysis of Cholla 4 and other coal unit environmental investment analysis going forward.

Wyoming Regional Haze

Sierra Club compares EPA's re-proposed FIP for Wyoming to base case and stringent case Regional Haze assumptions applied in the IRP, highlighting the potential need for incremental investments at Dave Johnston 3 and 4 and at Naughton 1 and 2. Sierra Club asserts that the Company is refusing to model environmental retrofit requirements for these units.

In response, PacifiCorp refers to its previous response to similar comments from other parties. PacifiCorp further states that it has never told parties that it would not model environmental investments. PacifiCorp has consistently maintained that it would perform the requisite analysis at the appropriate time and in an appropriate venue.

System Optimizer Model and Risk of Coal

Sierra Club asserts that the IRP does not provide any information allowing parties to estimate the degree to which a certain plan is optimal. In the purported absence of such information, Sierra Club continues to discuss its own analysis of specific environmental investments using a version of the Company’s screening model provided to Sierra Club through discovery.

In response, PacifiCorp states that Sierra Club’s assertion is not factual. Confidential Volume III of the 2013 IRP provides comprehensive PVRR(d) analysis across a broad range of natural gas and CO_2 price assumptions. These PVRR(d) results, reported from the System Optimizer model, specifically quantify the degree to which a given compliance plan is optimal among each of the scenarios reported. PacifiCorp further refers to its previous response to comments on the screening.

Class 2 DSM

In Sierra Club’s opening comments, it expresses concern with the Company’s planning process where energy efficiency and demand-response resources compete with supply-side resources, or are optimized by cost and risk, in the IRP model. They acknowledge that the process has its advantages from a planning perspective, but argue that it fails from a practical standpoint as it yields results that show a declining pathway of incremental energy efficiency investments each year throughout the planning horizon, except in Wyoming.

The declining pathway is reflective of the energy efficiency opportunities identified in both the Company's conservation potential assessment study and that of the ETO. Prior efficiency efforts, national and state code and standards improvement, and a limited view of emerging technologies and their impact beyond a three-to-five year window all contribute to the declining pathway. With revised conservation potential assessments being conducted every two years, parties should not be overly concerned with a declining pathway provided that known opportunities are being selected and actively pursued within the near-term action plan period. It is not practical to assume that, with improving energy efficiency baselines and aggressive lighting standards, the pathway would be anything but declining over time.

Transmission Analysis and IRP Models

Sierra Club questions the efficacy of the PaR model given its use as part of the SBT in quantifying the System Cost Savings benefit and concern around the Customer and Regulatory benefit category of the SBT.

In response, PacifiCorp refers to its response to CUB's opening comments on transmission. PacifiCorp further responds by emphasizing that the SBT does not highlight shortcomings of the PaR model as used to analyze portfolios for the 2013 IRP as suggested by Sierra Club. The PaR model is a production cost dispatch model widely deployed for planning analysis throughout the industry. As discussed throughout the Company's reply comments, PaR is configured with stochastic simulation capabilities that allows for portfolio risk analysis that informs selection of a preferred resource portfolio. PaR is not a transmission power flow model, and is not intended to analyze how transmission investments might physically impact transmission system attributes such as voltage, impedance, resistance and other engineering-based variables. PacifiCorp is simply using the SBT, specific to its analysis of transmission investments, as a means to capture potential transmission benefits that the PaR model was never intended to analyze. The SBT supplements PaR results; however, it does not indicate that the PaR model is inadequate when it is used for its intended purpose.

<u>California Independent System Operator (CAISO) and Renewables</u>

Sierra Club notes PacifiCorp's joint announcement with the CAISO to form an energy imbalance market (EIM), and questions whether there will be a higher value placed on flexible resources within the PacifiCorp System given the prospect of PacifiCorp sharing resources with California. Sierra Club comments that given a large renewable build anticipated in California, that flexible resources will have a very high value, and asserts that the value of selling ancillary services should be considered in the Company's resource choices.

Importantly, Sierra Club's argument is misplaced because EIM does not include an ancillary services market. Further, the EIM market design requires the CAISO and the EIM Entity to independently demonstrate sufficient flexible resources before any EIM transfers are permitted between the CAISO and EIM Entities. Nonetheless, PacifiCorp believes market mechanisms outside the EIM may develop in the future that would enable the sale of flexible capacity to support an increasingly renewables-based grid and will continue to monitor market developments for potential consideration in future IRPs.

11. NRDC OPENING COMMENTS

<u>Federal CO_2 Regulation</u>

NRDC comments that after PacifiCorp's 2013 IRP filing, President Obama provided direction to EPA to initiate a rulemaking limiting GHG emissions from existing power plants. NRDC further highlights that in May 2013, the US Interagency Working Group on Social Cost of Carbon issued an updated cost range for CO_2 emissions. Based on these events, NRDC asserts that PacifiCorp's IRP assumptions are outdated.

In response, PacifiCorp refers to its previous responses to other parties' comments regarding the June 2013 Presidential Memorandum, CO_2 costs assumptions, and the social cost of carbon.

<u>Climate Change</u>

Referencing a U.S. Department of Energy report (DOE Report) on electric power system vulnerabilities to a range of climate change phenomena, NRDC states that PacifiCorp has omitted climate impacts from its 2013 IRP. NRDC claims this raises questions regarding the Commission's acknowledgement of the Company's 2013 IRP.

In response, PacifiCorp notes that its current modeling framework includes Monte Carlo random sampling of both hydro and thermal unit availability. Moreover, PacifiCorp recognizes that there are many uncertainties that could be studied in long-term planning efforts. Some uncertainties are best captured through stochastic risk analysis (market price volatility, short-run load volatility, and unit availability), while others are more appropriately analyzed through scenario analysis (policy, technology shifts, etc.). PacifiCorp's 2013 IRP process captured a broad range of both stochastic and scenario risks and these analyses are factored into selection of a preferred portfolio and Action Plan. PacifiCorp further recognizes that it must be resilient and adapt to emerging risks as it continuously updates its long-term plans.

At present, there is tremendous uncertainty about how climate change might specifically impact PacifiCorp's system and an equal level of uncertainty around how climate change scenarios might be best analyzed in the context of an IRP. In fact, the DOE Report referenced by NRDC cites the need for improved data and models. In addition to the uncertain impacts on hydro and thermal unit availability, the DOE Report identifies potential implications for variation in wind patterns with uncertain impacts on wind resource potential and potential for reduction in solar generation capacity. As concrete data and improved modeling capabilities are developed that allow for a holistic assessment of how climate change might influence a broad range of input assumptions, PacifiCorp will work with its stakeholders to evaluate these impacts in future IRPs.

12. CONCLUSION

PacifiCorp's 2013 IRP complies with the Commission's standards and guidelines. The 2013 IRP also reflects a balanced consideration of customer interests and is well supported by portfolio modeling and prudent planning assumptions leading to selection of a least cost preferred portfolio that is consistent with the long-run public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group, and continues to urge stakeholder participation throughout the IRP development process to foster constructive dialogue.

PacifiCorp requests that the Commission support its proposed planning and review process, implemented in a docket separate from the IRP, which will allow parties to review a more timely analysis of coal unit investment decisions in advance of a prudence review through a general rate case. PacifiCorp further requests that the Commission acknowledge the 2013 IRP, and the 2013 IRP Action Plan, including the following specific action items:

- Action Item 8a, pertaining to the natural gas conversion of Naughton 3;
- Action Item 8b, pertaining to the baghouse conversion and low NO_X burner (LNB) investments required at Hunter 1;
- Action Item 8c, pertaining to the selective catalytic reduction (SCR) investments required at Jim Bridger 3 and 4; and
- Action Item 9c, pertaining to the Sigurd to Red Butte 345 kilovolt transmission line.

DATED: November 26, 2013

Mary Wiencke
Senior Attorney, Pacific Power
Counsel for PacifiCorp

Attachment A

State of Utah
GARY R. HERBERT
Governor

GREG BELL
Lieutenant Governor

Department of
Environmental Quality

Amanda Smith
Executive Director

DIVISION OF AIR QUALITY
Cheryl Heying
Director

DAQP-0001-11

January 3, 2011

Callie Videtich
Director Air Program
EPA Region 8
1595 Wyncoop St
Denver, CO 80202-1129

Dear Ms. Videtich,

In 2008, Governor Huntsman submitted a revision to Utah's Regional Haze SIP to address, in part, the requirements in 40 CFR 51.309(d)(4)(vii) *Provisions for stationary source emissions of NOx and PM.* This revision contained an analysis of best available retrofit technology (BART) for NOx and PM. During subsequent conversations with your staff, questions were raised regarding the 5-factor analysis that is outlined in 40 CFR Part 51, Appendix Y, and the enforceability of the current emission limits for the Hunter and Huntington plants in Utah. The attached document is a more complete explanation of how these two issues were addressed in the 2008 SIP.

Thank you for your continued support as we work towards final approval of Utah's Regional Haze SIP.

Sincerely,

M. Cheryl Heying
Director

Attachment

195 North 1950 West • Salt Lake City, UT
Mailing Address: P.O. Box 144820 • Salt Lake City, UT 84114-4820
Telephone (801) 536-4000 • Fax (801)536-4099 • T.D.D. (801) 536-4414
www.deq.utah.gov

December 20, 2010

Supplement to the Technical Support Documentation for Utah's 2008 Regional Haze SIP

On September 3, 2008, the Utah Air Quality Board adopted a revision to Utah's Regional Haze State Implementation Plan (SIP). This revision addressed Best Available Retrofit Technology (BART) requirements for NO_x and particulate matter (PM), as required by 40 CFR 51.309(d)(4)(vii). The SIP generally relies on EPA's presumptive BART emission rate for NO_x as the appropriate benchmark and, because EPA has not established a presumptive rate for PM, the SIP relies on technical work completed by the WRAP for PM. The purpose of this supplement is to more fully explain the analysis that was completed by UDAQ for the 2008 SIP.

While the SIP relies on presumptive emission rates for NO_x as the appropriate benchmark, the SIP also includes a BART analysis for NO_x, as required by 40 CFR Part 51, Appendix Y that is summarized in Section D.6.d of the SIP. EPA completed extensive technical work to develop presumptive limits for NO_x, now codified in Appendix Y.[1] In addition, the Western Regional Air Partnership (WRAP) evaluated the impact of PM, as well as other pollutants. Utah's BART analysis relies on both of these works.

The BART analysis performed by UDAQ was influenced by several important factors.

1. In the 1990s PacifiCorp installed first generation low NO_x burners on the four electric generating units (EGUs) that are subject to BART. As can be seen on the table below, Utah's ability to achieve significant NO_x reductions that may have been available at older uncontrolled plants was limited because of these previously installed low NO_x burners. Moreover, it is less cost effective to install controls on a lower-emitting plant than on an uncontrolled plant.

	Pre-control emission rate (lb/MMBtu)	NO_x Controls Installed prior to 2004	2004 NOx emission rate with first generation low NO_x burners (lb/MMBtu)
Hunter Unit 1	0.50	LNC1 (Installed: 06/01/1999 – Still in service)	0.35
Hunter Unit 2	0.55	LNC1 (Installed: 10/01/1997 -- Still in service)	0.35
Huntington Unit 1	0.52	LNC1 (Installed: 06/01/1997 – Still in service)	0.34
Huntington Unit 2	0.43	LNC1 (Installed: 06/01/1998 -- Still in service)	0.36

[1] 40 CFR Part 51, Appx Y, Table 1, Presumptive NO_x Emission Limits for BART-Eligible Coal-Fired Units, note 20, says:

> These [presumptive NO_x] limits reflect the design and technological assumptions discussed in the technical support document for NO_x limits for these guidelines. See Technical Support Document for BART NO_x Limits for Electric Generating Units and Technical Support Document for BART NO_x Limits for Electric Generating Units Excel Spreadsheet, Memorandum to Docket OAR 2002–0076, April 15, 2005.

The information in the above table is drawn from the "Technical Support Document for BART NO_x Limits for Electric Generating Units Excel Spreadsheet" (see footnote 1 above) and included in the TSD for Utah's RH SIP.

2. In 2005 PacifiCorp began major pollution control projects, including the installation of next generation low NO_x burners, at the four EGUs that are subject to BART. The projects were described in the commitments made by MidAmerican Energy Holdings Company to the Utah Public Service Commission when purchasing PacifiCorp in 2005. The projects were based on the regulatory framework established in Utah's 2003 regional haze SIP and the 2005 Clean Air Mercury Rule as well as EPA's BART guidelines that were finalized in 2005.

The pollution control projects were designed to achieve overall emission reductions not only of NO_x but also of SO_2, PM, and mercury. The emission rates that were ultimately included in the permits for these pollution control projects for NO_x and PM are shown in Table 5 of Utah's RH SIP and summarized below.

	Utah Permitted Rate (pollution control project) in lb/MMBtu		Presumptive NO_x limit established in Appendix Y (lb/MMBtu)
	NO_x	PM	
Hunter Unit 1	0.26	0.015	0.28
Hunter Unit 2	0.26	0.015	0.28
Huntington Unit 1	0.26	0.015 (74 lb/hr)	0.28
Huntington Unit 2	0.26	0.015 (70 lb/hr)	0.28

As can be seen from the table above, the pollution control projects at the Hunter and Huntington Plants, including installation of low NO_x burners, achieve the presumptive BART limits for NO_x, as currently codified in 40 CFR 51, Appendix Y Section IV.E.5 that states:

> For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls (i.e., SCR or SNCR), **we have provided presumptive NO_x limits**, differentiated by boiler design and type of coal burned. You may determine that an alternative level is appropriate based on a careful consideration of the statutory factors. *Emphasis added.*

Utah's RH SIP relies on the presumptive BART limit for NO_x as the appropriate benchmark, and Utah did not choose to follow the voluntary path to establish an alternative level. This decision was based on a careful review of the supporting documentation that EPA developed to support the presumptive NO_x limits in Appendix Y.

4. The Grand Canyon Visibility Transport Commission determined that sulfates were the primary stationary source pollutant of concern in the sixteen Class I areas on the Colorado Plateau. Utah's RH SIP, based on the Commission's

recommendations, established a regulatory framework that required stationary sources to focus their resources on reductions in SO_2. The 2003 SIP included a regional SO_2 milestone with a backstop trading program that locked in substantial SO_2 emission reductions, and also included allocation provisions to encourage early reductions.

The milestones in the 2003 SIP required substantial SO_2 reductions in the region. If the milestones were not met, sources in the region would face significant financial penalties and the implementation of a mandatory trading program. The milestones provided flexibility for companies such as PacifiCorp to schedule projects across their fleet of plants in the most cost-effective manner, as long as the regional emission reduction goals were achieved. The milestones could not be met unless major sources achieved the assumed emission reductions in the SIP. After the 2003 had been finalized, there was a huge growth in applications for new power plants in response to the California energy crisis of 2000 and 2001, putting further pressure on existing sources to reduce emissions to meet the milestones. The 2003 SIP also contained a commitment to address BART for NO_x and PM by 2008 with installation of controls within 5 years, as required by the regional haze rule.

PacifiCorp's pollution control projects were developed within this regulatory framework, and achieved the substantial reductions of SO_2 that were needed to ensure that the SO_2 milestones would be met. PacifiCorp's projects planned across their large fleet of plants, were done in an ordered manner and achieved cost savings by timing the upgrades to coincide with other planned maintenance at the plants, achieving significant early reductions in the process.

The overall level of control in Utah's RH SIP was weighted to achieve SO_2 reductions because SO_2 reductions would lead to the greatest improvement in regional haze. PacifiCorp's pollution control project reflected this weighting by achieving substantial reductions of SO_2 with an emission rate of 0.12 lbs/MMBtu, which is an emission rate lower than the presumptive rate of 0.15 lbs/MMBtu established in 40 CFR Part 51, Appendix Y, Section IV.E.4. This high level of control, needed to meet the SO_2 milestones, meets Utah's unique and dual needs of reducing SO_2 emissions and achieving NO_x emissions below EPA's presumptive emissions rate.

The Commission's recommendations to reduce NO_x emissions were focused on mobile sources that are the most significant source of NO_x in the region. The WRAP provided further analysis of the need for additional measures to address NO_x emissions from stationary sources in a document titled *Stationary Source NO_x and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts* dated October 1, 2003. This report concludes that stationary source NO_x emissions probably cause 2% - 5% of the visibility impairment on the Colorado Plateau. The BART analysis for NO_x was developed within the context of the substantial SO_2 reductions that had been achieved in the 2003 SIP.

5. In 2005, EPA finalized the Clean Air Mercury Rule (CAMR) that established a national trading program for mercury. This trading program, designed to reduce mercury emissions from EGUs nationwide, allowed sources that could make cost-effective reductions to reduce mercury emissions and then sell the excess allowances to other plants that could not achieve the reductions in a cost-effective manner. The CAMR trading program was adopted into Utah's SIP in 2007. While the CAMR rule has since been vacated, emissions of mercury are an important concern. This is particularly the case in Utah where elevated mercury levels have been measured in fish and have also been measured in waterfowl at the Great Salt Lake, an internationally important migratory bird resource. The State of Utah has identified reduction of mercury emissions as a priority for the State. When looked at in a multi-pollutant context, there is a strong rationale to focus resources where benefits beyond visibility can be achieved. Baghouses to reduce PM in conjunction with wet scrubbers to reduce SO_2 can significantly decrease mercury emissions. PacifiCorp's pollution control project was consistent with this multi-pollutant approach to achieve broad benefits in the most cost-effective way.

6. The overall pollution control projects at the Hunter and Huntington plants achieved early reductions that are already benefiting the Class I areas in Utah and in neighboring states.

Because of these overarching factors, UDAQ determined that it would be appropriate to compress the 5-factor BART analysis by focusing on the NO_x and PM emission controls that had already been achieved at the Hunter and Huntington plants.

BART Analysis for NO_x

Step 1. The available retrofit control options and Step 2. Eliminate technically infeasible options.

As the EPA had already provided a substantial analysis of potential NO_x controls at EGUs throughout the nation, UDAQ relied heavily on that analysis to address the first two steps in the BART analysis for NO_x.

EPA's analysis identified three levels of feasible control that are described in Table 1 of the Methodology for Developing BART NO_x Presumptive Limits and reproduced below as well as included in the TSD for Utah's SIP.

Table 1. Coal-fired Control Cases

Control Case	Control Action Taken	Major Assumptions/Notes
1a	Installation of current NO_x combustion controls for units with no prior controls, or which had controls installed before 1997. For units with controls installed in or after 1997, install incremental controls if a complete set of combustion controls was not installed (LNBO or LNC3). For Cyclone units, apply Coal Reburn if no prior controls installed. For Cell Burners, install Current Combustion Controls if the unit had no controls or controls were installed before 1997. For Stokers install overfire air (OFA). Do not include existing SCR or SNCR units in the Control Case NO_x Rate.	If the 2004 NO_x rate was less than the floor rate or the new controlled rate, no controls added. Used average heat input from 2002 – 2004 to calculate an Average NO_x Rate. Assume 10,000 BTU/ kWh heat rate for coal-fired boilers. The heat rate is a measure of how much fuel energy needed to get electric energy out. Therefore, 1,000,000 Btu/yr divided by 10,000 Btu/kWh = 100 kWh-yr. Multiply Avg Heat Input (mmBtu) by 100 to get kWhyr.
1d	Install SCR, unless unit already has SCR installed or the 2004 NO_x rate is already at or below the SCR floor rate.	
1e	Install rotating opposed fire air (ROFA), unless unit already has SCR or the 2004 NO_x Rate is already at or below the ROFA floor rate. Also, for Cyclone units, install SCR. Do not include units with existing SCR/SNCR in the Control Case NO_x Rate.	

Step 3. Evaluate Control Effectiveness of Control Technologies
UDAQ used EPA's analysis to determine the effectiveness of each option.

	Case 1a (increase to LNC3)		Case 1d (SCR)		Case 1e (ROFA)	
	NO_x emission rate	tons reduced	NO_x emission rate	tons reduced	NO_x emission rate	tons reduced
Hunter 1	0.28	1,233	0.06	5,108	0.19	2,642
Hunter 2	0.28	1,131	0.06	4,685	0.19	2,423
Huntington 1	0.27	1,084	0.06	4,462	0.19	2,231
Huntington 2	0.29	1,082	0.06	4,507	0.20	2,404

Step 4. Evaluate Impacts
UDAQ used EPA's analysis to determine the cost of compliance for each option. A few key items from EPA's analysis are provided in the following table.

	Case 1a (increase to LNC3)			Case 1d (SCR)			Case 1e (ROFA)		
	total annual cost	tons reduced	cost/ton	total annual cost	tons reduced	cost/ton	total annual cost	tons reduced	cost/ton
Hunter 1	$367,235	1,233	$298	$6,772,337	5,108	$1,326	$1,889,141	2,642	$715
Hunter 2	$360,235	1,131	$319	$6,606,657	4,685	$1,411	$1,889,141	2,423	$780
Huntington 1	$359,195	1,084	$331	$6,584,352	4,462	$1,476	$1,889,141	2,231	$847
Huntington 2	$354,802	1,082	$328	$6,481,622	4,507	$1,438	$1,889,141	2,404	$786

Case 1a, increase to LNC3, assumes an upgrade to current low NO_x burner technology. This case is the closest to Pacificorp's pollution control project. Case 1d is the installation of post combustion controls (selective catalytic reduction). Case 1e is the installation of an emerging technology called rotating opposed fire air (ROFA).

PacifiCorp's calculations of the costs associated with SCR are much higher that what is shown in this table. PacifiCorp estimates that the costs would be $4,500 - $5,500 per ton removed.

The cost/ton in Cases 1d and 1e are significantly higher than the $567/ton that is shown as the average cost-effectiveness of NO_x controls for BART-eligible coal fired units in Table 3 of EPA's July 6, 2005 final BART rule (70 Fed. Reg. 39135). Appendix Y on its face shows that an alternative analysis is required only when a source cannot meet the presumptive NO_x limits. 40 CFR Part 51, Appendix Y, Section IV.E.5 states,

> **Most EGUs can meet these presumptive NO_x limits** through the use of current combustion control technology, i.e. the careful control of combustion air and **low-NO_x burners.** For **units that cannot meet these [presumptive] limits using such technologies**, you should consider whether advanced combustion control technologies such a rotating opposed fire air should be used to meet these limits. (*Emphasis* added)

The preamble discussion of the presumptive limits supports this reading of Appendix Y. It clearly states that the presumptive limits are reasonable, but the preamble also recognizes that in some limited cases, where a source could not meet that limit, the state could demonstrate an alternative level of control.

> "States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits. We are establishing these requirements based on the consideration of certain factors discussed below. Although **we believe that these requirements are extremely likely to be appropriate for all greater than 750 MW power plants subject to BART**, a State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors....A State is free to reach a different conclusion **if the State believes that an alternative determination is justified** based on a consideration of the five statutory factors. Nevertheless, our analysis indicates that these controls are likely to be among **the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement.**"
>
> . . . .
>
> "EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NO_x limits set forth here today are presumptions only; in making a BART determination, States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate."
>
> . . . .
>
> "We assumed that coal-fired EGUs would have space available to install separated overfire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is possible, however that some EGUs may not have adequate space available. In such cases, other NO_x combustion control technologies could be considered such as Rotating Opposed Fire Air ("ROFA").
>
> . . . .
>
> "Although states may in specific cases find that the use of SCR is appropriate, **we have not determined that SCR is generally cost effective** for BART across unit types."
>
> 70 Fed. Reg. 39,131, and 39,134-36. (Emphasis added)

What comes through from the BART regulations in Appendix Y and the discussion in the preamble to the BART rule is that the presumptive NO_x level is adequate and expected for most sources, and only if a source is not able to meet the presumptive BART limits is an alternate analysis required.

BART Analysis for PM

EPA did not establish a presumptive BART limit for PM. The pollution control projects at the Hunter and Huntington plants upgraded the PM controls from electrostatic precipitators to baghouses, which is the current standard control technology for EGUs. 40 CFR Part 51 Appendix Y Section IV.D, Step 1: Item 9 states:

> If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section

The visibility impact from stationary source PM emissions is not as significant as the impact from SO_2 and NO_x. However, when viewed in a broader, multi-pollutant approach, the combination of SO_2 controls and PM controls are very effective at reducing mercury emissions.

The SIP determined that the emission rate under the pollution control project met or was better than BART.

Enforceability

Utah's State Implementation Plan concluded that the level of control already in place at the Hunter and Huntington Plants satisfied the BART requirement. Therefore the SIP does not establish a BART emission limit. To put it in a different way, the SIP concluded that BART was not an additional control and this determination does not require an emission limit. This determination is reasonable because Utah's broad SIP and permit program ensure that the underlying permits and regulations that are already applicable to the Hunter and Huntington plants are enforceable by both the State and EPA.

Utah's State Implementation Plan and the permits that are issued under that plan are enforceable under State law and become federally enforceable when EPA approves the plan and incorporates it into 40 CFR Part 52, Subpart TT. The following general description of this process is drawn from the Environmental Protection Agency, Region 8's web page (http://www.epa.gov/region8/air/sipreq.html).

> Several sections of the Clean Air Act (Act or CAA) describe the states' planning obligations to achieve healthy air quality. Section 110 of the Act requires states to submit state implementation plans (SIPs) to EPA which provide for implementation, maintenance, and enforcement of the primary and secondary National Ambient Air Quality Standards (NAAQS) established by EPA under Title I of the Act. Section 172, and other provisions in Title I, Part D, of the Act identify additional SIP requirements for areas that do not meet the NAAQS and that have been designated as nonattainment under section 107 of the Act. Section 175A of the Act describes the maintenance plan requirements for states wishing to redesignate an area from nonattainment to attainment.

> Additionally, SIPs contain state air regulations that, for example, allow states to permit the construction and operation of stationary sources, establish specific requirements for categories of stationary sources, and identify open burning requirements.
>
> Each SIP revision submitted by the state must undergo reasonable notice and public hearing at the state level, and SIPs submitted to EPA to attain or maintain the NAAQS must include enforceable emission limitations and other control measures, schedules and timetables for compliance.
>
> EPA evaluates submitted SIPs to determine if they meet the Act's requirements. If a SIP meets the Act's requirements, EPA will approve the SIP. EPA's notice of approval is published in the Federal Register and the approval is then codified in the Code of Federal Regulations (CFR) at 40 CFR Part 52. Once EPA approves a SIP, it is enforceable by EPA and citizens in federal district court.

Approval orders and Title V operating permits issued by the Executive Secretary of the Utah Air Quality Board are also federally enforceable. Approval orders become federally enforceable through R307-401 *Permits: New and Modified Sources*, and R307-405 *Permits: Major Sources in Attainment or Unclassified Areas (PSD),* when those rules are are approved by EPA as part of Utah's SIP and codified in 40 CFR. § 52.2320 and 40 CFR 40 CFR § 52.2346. Under Title V of the Clean Air Act, EPA has broad general authority to enforce state-issued Title V permits. EPA approved Utah's Operating Permit Program and codified that approval in 40 CFR Part 70, Appendix A on July 10, 1995.

Approval Orders issued by the Executive Secretary under authority of R307-401 and R307-405 to the Hunter and Huntington plants, including provisions to make the pollution control projects enforceable, contain enforceable emission limits for NO_x and PM, as well as monitoring, recordkeeping, and reporting requirements to ensure that the emission limits are continuously met. EPA has discretion to federally enforce the provisions of these approval orders under authority of the federally approved Utah SIP. There is no doubt that such approval orders are federally enforceable, as evidenced by lawsuits brought previously by EPA against other sources in Utah.

The applicable requirements in the approval orders for the Hunter and Huntington plants have been incorporated into the operating permits for these plants under authority of R307-415. The operating permit program was designed to ensure that applicable requirements are clear and are enforceable. A source that violates one or more enforceable permit conditions is subject to an enforcement action including, but not limited to, penalties and corrective action. Enforcement actions may be initiated by the local permitting authority (UDAQ), EPA or, in many cases, through citizen suits.

Utah's new source review program for major and minor sources is part of the federally approved SIP. If PacifiCorp seeks to relax or modify the limitations in the approval orders for the Hunter or Huntington plants at some point in the future, the company would be required to obtain a new approval order and apply BACT under either Utah's major source (R307-405) or minor source (R307-401) rules. A modification may potentially trigger other requirements, such as PSD review, NSPS standards, GHG review, or analysis of impact on new NAAQS. As has been evident throughout the federal Clean Air Act programs that EPA has delegated to Utah, there are substantial federally enforceable requirements in the broad air program in Utah to ensure that the emission reductions achieved through the pollution control projects are maintained (through state or federal enforcement if necessary) into the future.

Conclusion

After reviewing the detailed analysis prepared by EPA in support of Appendix Y, and reviewing whether that rate was achievable at the Hunter and Huntington plants, UDAQ agreed with EPA's presumptive BART emission rate for NO_x as applied to those Utah plants. As the Hunter and Huntington Plants already meet the presumptive NO_x emission rate in Appendix Y, no additional NO_x controls were needed to meet the BART requirement.

EPA has not established a presumptive BART emission rate for PM. However, the baghouses that are already required at the two plants meet or are better than BART and, therefore, no additional PM controls were needed to meet the BART requirement.