PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

November 7, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: UE 246 – PacifiCorp's Post-Hearing Brief

PacifiCorp d.b.a. Pacific Power hereby submits for filing an original and five (5) copies of its Post-Hearing Brief in the above-referenced proceeding.

Please direct informal correspondence and questions regarding this filing to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith/RBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 246 Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 246, on the date indicated below by email, addressed to said parties at his or her last-known address(es) indicated below.

Kurt J. Boehm (W)(C)
Boehm Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com

Jody Kyler (W)(C)
Boehm Kurtz & Lowry
36 E. Seventh St. Ste 1510
Cincinnati, OH 45202
jkyler@bkllawfirm.com

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
dockets@oregoncub.org

Robert Jenks (W)(C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
Bob@oregoncub.org

G. Catriona McCracken (W)(C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
catriona@oregoncub.org

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

Melinda J. Davison (W)(C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
mail@dvclaw.com

Kevin Higgins (W)(C)
Energy Strategies
215 State St., Suite 200
Salt Lake City, UT 84111-2322
Khiggins@energystrat.com

Michael T. Weirich (W)(C)
Department of Justice
Regulated Utility & Business Section
1162 Court St. NE
Salem, OR 97301-4096
Michael.weirch@doj.state.or.us

John W. Stephens (W)(C)
Esler Stephens & Buckley
888 SW 5th Ave Ste 700
Portland, OR 97204 - 2021
stephens@eslerstephens.com
mec@eslerstephens.com

Johanna Riemenschneider (W)(C)
PUC Staff – Dept of Justice
Business Activites Section
1162 Court St NE
Salem, OR 97301-4096
Johanna.riemenschneider@doj.state.or.us

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

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

Bryce Dalley (W)(C)
Pacific Power
825 NE Multnomah St., Suite 2000
Portland, OR 97232
Bryce.dalley@pacificorp.com

Sarah Wallace (W)(C)
Pacific Power
825 NE Multnomah St Ste 1800
Portland, OR 97232
Sarah.wallace@pacificorp.com

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

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

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

Deborah Garcia (W)(C)
Oregon Public Utility Commission
PO Box 2148
Salem, OR 97308-2148
deborah.garcia@state.or.us

Jimmy Lindsay (W)(C)
Renewable Northwest Project
421 SW 6th Ave #1125
Portland, OR 97204-1629
jimmy@rnp.org

Stuart Robertson (W)
Robertson-Bryan, Inc
9888 Kent Street
Elk Grove, CA 95624
stuart@robertson-bryan.com

William Ganong (W)(C)
514 Walnut Avenue
Klamath Falls, OR 97601
wganong@aol.com

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

Douglas C. Tingey (W)
Portland General Electric
121 SW Salmon St., 1WTC13
Portland, OR 97204
doug.tingey@pgn.com

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

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

Kevin E. Parks (W)
Parks Law Offices LLC
310 SW 4th Ave. Ste 806
Portland, OR 97204
kevin@parks-law-offices.com

Hollie Cannon (W)(C)
Klamath Water and Power Agency
735 Commercial St Ste 4000
Klamath Falls, OR 97601
Hollie.cannon@kwapa.org

DATED: November 7, 2012

Carrie Meyer
Coordinator, Regulatory Operations

PACIFICORP PROJECTS COMPLETED 2006 - 2014

PACIFICORP OPERATED COAL UNITS – PERMIT EFFECTIVE DATES	
Plant Name	SO_2 Scrubber Installation or Upgrade
Hunter 1	Previous Limit: 80% Removal or 0.21 lb/mmBtu, whichever is less New Limit: 0.12 lb/mmBtu Compliance date: 2014 Enforcement Mechanisms: Approval Order, State SIP, Backstop Trading Program
Hunter 2	Previous Limit: 80% Removal or 0.21 lb/mmBtu, whichever is less New Limit: 0.12 lb/mmBtu Compliance Date: January 25, 2012 Enforcement Mechanisms: Approval Order, State SIP, Backstop Trading Program
Huntington 1	Previous Limit: 80% Removal or 0.21 lb/mmBtu, whichever is less New Limit: 0.12 lb/mmBtu Compliance Date: March 30, 2007 Enforcement Mechanisms: Approval Order, State SIP, Backstop Trading Program
Huntington 2	Previous Limit: Sulfur content of coal cannot exceed 1 lb/mmBtu gross heat input New Limit: 0.12 lb/mmBtu (emission rate) Compliance Date: July 28, 2011 Enforcement Mechanisms: Approval Order, State SIP, Backstop Trading Program
Dave Johnston 3	Previous Limit: 1.2 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: December 2010 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Dave Johnston 4	Previous Limit: 0.5 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: July 2012 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Jim Bridger 1	Previous Limit: 0.3 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: July 2010 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Jim Bridger 2	Previous Limit: 0.3 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: July 2009 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Jim Bridger 3	Previous Limit: 0.3 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: July 2011 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Jim Bridger 4	Previous Limit: 0.3 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: July 2008 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Naughton 1	Previous Limit: 1.2 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: June 29, 2012 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Naughton 2	Previous Limit: 1.2 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: February 9, 2012 Enforcement Mechanisms: Construction Permit, Backstop Trading Program
Naughton 3	Previous Limit: 0.5 lb/mmBtu New Limit: 0.15 lb/mmBtu Compliance Date: 2014 Enforcement Mechanisms: Backstop Trading Program
Wyodak	Previous Limit: 0.5 lb/mmBtu New Limit: 0.16 lb/mmBtu Compliance Date: May 29, 2011 Enforcement Mechanisms: Construction Permit, Backstop Trading Program

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.

PACIFICORP'S POST-HEARING BRIEF

NOVEMBER 7, 2012

TABLE OF CONTENTS

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) respectfully submits this post-hearing brief to address the three remaining disputed issues in this case: (1) the inclusion in rates of the Company's investments in emissions control equipment at some of its coal-fueled generating units; (2) the Company's proposed power cost adjustment mechanism (PCAM) and existing transition adjustment mechanism (TAM); and (3) the appropriate timing of the Company's recovery of the costs of its investment in the Mona-to-Oquirrh transmission project.[1]

Emissions Control Equipment. Two of the remaining issues in this case—the PCAM and the timing of the inclusion in rates of the costs of the Mona-to-Oquirrh transmission project—are policy issues. The third issue—the prudence of the Company's emissions control investments—is not a policy issue; it is strictly an issue of fact and law. Despite this context, the Citizens' Utility Board of Oregon (CUB) and the Sierra Club attempt to distract the Commission with policy arguments designed to further their stated commitments to eliminate coal-fired generation[2] and mischaracterize the law and facts. Contrary to CUB's and Sierra Club's arguments, at the time the Company made the decisions to invest in the emissions control equipment at issue in this case (2008 and 2009) the following facts and circumstances existed:

- The investments were consistent with the Commission-acknowledged integrated resource plans (IRP) in effect in 2008 and 2009, which included continued operation of the units at issue in this case through the end of their useful lives, the costs of the known and reasonably anticipated emissions control equipment necessary to continue operating the units in compliance with environmental laws and regulations, and a carbon dioxide (CO_2) risk analysis.[3]

---

[1] Because no party opposes adoption of the partial stipulation, no further discussion of it is included in this brief. *See* PacifiCorp's Prehearing Brief at 5-7 (October 4, 2012).

[2] One of the CUB policy center's current projects is named "Transition from Coal": "The CUB Policy Center is working to investigate and evaluate alternative energy resources that could effectively replace coal as baseload coal-fired plants become decommissioned. . . . We believe fundamentally . . . that this project represents an urgent need for the Pacific Northwest." *See* http://cubpolicycenter.org/projects (last visited November 6, 2012). Sierra Club's "Beyond Coal" campaign is dedicated to eliminating coal-fired generation: "With the 100th coal-fired power plant retirement announced in February 2012, the Sierra Club reached a major milestone in its goal to retire one-third of the nation's aging coal plants by 2020 and replace them with clean energy." *See* http://www.beyondcoal.org (last visited November 6, 2012).

[3] In 2008 and 2009, the Company's 2007 and 2008 IRPs were the operative plans. *See In re PacifiCorp 2007 IRP*, Docket No. LC 42, Order No. 08-232 (filed May 30, 2007; acknowledged Apr. 24, 2008); *In re PacifiCorp 2008 IRP*, Docket No. LC 47, Order No. 10-066 (filed May 29, 2009, acknowledged Feb. 24, 2010).

- In both IRP orders, the Commission explicitly found that the Company met the requirements of IRP Guideline 8, which governs the inclusion of environmental costs in the IRP process.[4]

- The investments were required by the states of Wyoming and Utah under the Clean Air Act and are necessary to continue operating the units as envisioned by the Company's IRPs.

- The Company committed to implementing a comprehensive emissions control program, including the projects at issue in this case, as part of MidAmerican Energy Holdings Company's acquisition of PacifiCorp in 2006.[5] The Company provided annual updates to the Commission (and to CUB) on the status and projected costs of the emissions control projects from 2007 through 2010.[6]

- No party argued that emissions control investments were required to be analyzed in a particular manner until the Company's 2011 IRP docket, well after the investment decisions at issue in this case were made.[7]

- There was no precedent for closing a plant early in exchange for a negotiated reduction in compliance obligations under the Clean Air Act. The Commission did not accept the Boardman plan as reasonable until 2010, and the United States Environmental Protection Agency (EPA) did not approve the plan until July 2011.[8]

- The Company conducted a least-cost, adjusted for risk, analysis of each of the emissions control investments and determined that the investments were cost-effective. In each case, the Company's present value revenue requirement differential (PVRR(d)) analysis shows that the investments were cost-effective for customers, supporting the "objective reasonableness" of those investments.

In addition, the Commission previously approved the Company's investments in emissions control equipment—made at the same time and using the same analyses as the emissions control investments in this case—as prudent.[9] Nothing has changed about the relevant facts or circumstances that existed at the time the Company's emission control investments were

---

[4] Order No. 08-232 at 27; Order No. 10-066 at 23.
[5] *In the Matter of MidAmerican Energy Holdings Co*., Docket UM 1209, Order No. 06-082 at 9 (February 24, 2006).
[6] *See* Exhibit PAC/1405/Woollums for the relevant excerpts from the annual status reports in Oregon from 2007 through 2011 (see Commitment 43). Copies of the full status reports are available on the Commission's website at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=12727
[7] *See In re PacifiCorp 2011 IRP*, Docket No. LC 52, Order No. 12-082 (Mar. 9, 2012).
[8] *In re PGE 2009 IRP*, Docket No. LC 48, Order No. 10-457 (Nov. 23, 2010); *Approval and Promulgation of Implementation Plans; State of Oregon; Regional State Implementation Plan and Interstate Transport Plan*, 79 FR 38997 (July 5, 2011) (available at: https://federalregister.gov/a/2011-16635).
[9] *In re PacifiCorp*, Docket No. UE 217, Order No. 10-473 at 15 (Dec. 14, 2010). *See also* PAC/500, Teply/50. Approval of a stipulation requires the Commission to independently conclude that the legal standard is met. *See In the Matter of PacifiCorp Petition for a Certificate of Public Convenience and Necessity*, Docket No. UM 1495, Order No. 11-121 at 1-2 (Apr. 11, 2011).

made to warrant reversal of the Commission's previous conclusions. The Company's disputed emissions control investments were also deemed prudent and used and useful by the Utah Public Service Commission (PSC), with the PSC rejecting arguments from Sierra Club that were almost identical to the arguments in this case.[10] The Commission should authorize inclusion in rates of the Company's emissions control investments.

PacifiCorp's Proposed PCAM. The Company proposes a PCAM that will allow the Company to collect or credit the difference between its actual net power costs (NPC) prudently incurred to serve Oregon customers and the amount of NPC recovered in Oregon rates.[11] The PCAM will operate in conjunction with the TAM and the Company's renewable adjustment clause (RAC) to: (1) address the Company's chronic NPC under-recovery and allow PacifiCorp the opportunity to recover its prudently incurred costs under ORS 756.040; (2) ensure that rates accurately reflect the Company's costs of complying with Senate Bill (SB) 838, Oregon's renewable portfolio standard (RPS); and (3) protect customers from paying NPC that the Company does not actually incur.

Recovery of the costs of compliance with SB 838—both fixed and variable—is authorized by ORS 469A.120(1). Since the passage of SB 838 in 2007, the significant increase in the amount of variable renewable resources on the Company's system has added significant new operational challenges, increased the volatility of the Company's NPC, and made it more difficult to accurately forecast NPC. While the TAM and the RAC address some aspects of SB-838-related cost recovery, these mechanisms alone are insufficient. As recognized by Standard & Poor's, the additional challenges presented by RPS compliance have increased

---

[10] *In re Rocky Mountain Power*, Docket Nos. 10-035-124 *et al*., Report and Order at 37-50 (September 13, 2011). Although this rate case was resolved via stipulation, the Utah Public Service Commission specifically addressed Sierra Club's arguments objecting to a finding of prudence for emission control investments, stating that "Sierra Club's general but unsupported opposition to [a finding of prudence for emission control investments] does not persuade us to reject the consensus reached by nearly all other parties that, in light of the totality of agreements embodied in the Settlement Stipulation, the pollution control investments in this case are prudent, and used and useful." *Id*. at 45-6. Wyoming has also approved inclusion of the emissions control investments in rates. *In re Rocky Mountain Power*, Docket No. 20000-405-ER-11, Memorandum Opinion, Findings and Order Approving Stipulation (October 8, 2012).

[11] *See* PAC/900, Duvall/14, lines 15-18.

business risk for utilities.[12] PacifiCorp's PCAM proposal is the only proposal that addresses this increased risk, ensures appropriate cost recovery as authorized by SB 838, and protects customers from paying NPC that are not actually incurred.

The Mona-to-Oquirrh Transmission Project. The Company proposes including the costs of its investment in the Mona-to-Oquirrh transmission project in rates through a separate tariff rider once the project goes into service during 2013. Because the parties to the partial stipulation agreed not to contest the prudence of the Company's decision to build the project and agreed to a process to review the final costs of the project, the only issue before the Commission is whether the inclusion of the costs of the project in rates should begin when the project begins serving customers. The Company's proposal ensures timely inclusion in rates of an investment in a transmission project that was acknowledged as part of the Company's IRP and is necessary to continue providing safe, reliable, and adequate service to its customers. Contrary to the arguments of Staff, ICNU, and CUB, the Company's proposal ensures the project is used and useful before the costs are included in customer rates and appropriately balances the costs borne and the benefits received by customers. The Commission should approve PacifiCorp's request for a separate tariff rider to be effective when the Mona-to-Oquirrh transmission project is placed into service.

II. RESPONSE TO COMMISSION BRIEFING QUESTIONS

On November 1, 2012, the Administrative Law Judge issued a memorandum asking PacifiCorp to respond to specific briefing questions. The Company responds to each of the Commission's questions below and divides Question 1 into separate questions and responses.

Question 1a: Did participation in the SO_2 Backstop Trading Program in Wyoming and Utah trigger any legally enforceable emissions limits or unit-specific pollution controls applicable to PacifiCorp's plants or units?

Yes. The SO_2 milestones established for the Regional SO_2 Milestone and Backstop Trading Program (the SO_2 Backstop Trading Program) were developed by setting specific

[12] *See* PAC/2314; PAC/2315.

emissions limits at each electric generating unit in Wyoming, Utah, and New Mexico, including the PacifiCorp coal-fueled generating units at issue in this docket (Naughton Units 1 and 2, Hunter Units 1 and 2, Jim Bridger Unit 3, Dave Johnston Unit 4, and Wyodak). These unit-specific SO_2 limits are incorporated into each unit's specific construction permit or approval order as required by EPA regulations:

> [A]n emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of [best available retrofit technology (BART)]. * * * [E]ach BART-eligible source in the State must be subject to the requirements of the alternative, have a ***federally enforceable emission limitation determined by the State*** and approved by the EPA as meeting BART[.][13]

In Wyoming, the emissions limit for each of PacifiCorp's coal-fueled units was set at 0.15 lb/mmBtu, which is the presumptive BART limit established by the EPA.[14] This limit was included in each unit's emissions control project construction permit. The Utah DEQ assumed that 90 percent removal efficiency could be achieved and set a 0.12 lb/mmBtu emission limit for each of PacifiCorp's units. This limit was included in each unit's emissions control project approval order. The states used these unit-by-unit emissions limits to calculate the regional emissions milestones.[15]

The intent of the SO_2 Backstop Trading Program is to ensure that SO_2 emissions remain below the milestones. The milestones must "provide for steady and continuing emissions reductions [through] 2018[.]"[16] If the regional emissions milestone is exceeded, the punitive trading program is triggered. Once triggered, if PacifiCorp does not meet its SO_2 emissions allocations, then the Company is subject to a $5,000 per ton penalty for each day that one of the

---

[13] 40 CFR 51.308(e)(2)(i)(B). The EPA approved the SO2 Backstop Trading Program on October 30, 2012. *[Prepublication] Approval, Disapproval and Promulgation of State Implementation Plans, State of Utah; Regional Haze Rule Requirements for Mandatory Class I Areas under 40 CFR 51.309*, EPA-R08-OAR-2011-0114 (October 30, 2012) ("*Final EPA Rule on Utah SIP*").

[14] *See* 40 CFR Part 51, Appendix Y.

[15] *See* EGU Data and Calculations Spreadsheet, available at http://www.wrapair.org/SIPStatus/309/index.html (follow XLS link titled "Milestone Spreadsheet Version 27 - typographical correction (04/29/09)") (showing each of the electric generating units subject to the SO2 Backstop and Trading Program, the unit-by-unit SO2 emissions limits, and the calculation of the 2018 milestone based on these limits). The historical and current WRAP websites (http://www.wrapair.org and http://wrapair2.org) provide helpful information about the program.

[16] 40 CFR 51.309(f)(i).

Company's sources exceeds its emissions allowances.[17] Because PacifiCorp's generating units are the largest source of SO_2 emissions in Utah and Wyoming, if PacifiCorp did not meet the emissions limits underlying the SO_2 Backstop Trading Program, the regional limit would be exceeded and the punitive trading program would be triggered. PacifiCorp's participation in the program is critical to the program's successful reduction of SO_2 emissions.[18]

Although the SO_2 Backstop Trading Program created regional SO_2 emissions milestones, the intent was to ensure emissions reductions throughout the region by setting emissions limits for each emitting source. In developing the SO_2 emissions limits for each emitting source, the states conducted modeling to ensure that the results of the SO_2 Backstop Trading Program would not "disproportionately impact any Class I area due to a geographic concentration of emissions."[19]

The EPA, the Utah Department of Environmental Quality (Utah DEQ), and the Utah PSC (among others) recognize that the SO_2 Backstop Trading Programs creates immediate compliance obligations, even before the trading program is triggered. In its recent rule approving the SO_2 Backstop Trading Program, the EPA recognized that the program is designed to create incentives for sources to actively reduce SO_2 emissions early:

> If the SO_2 milestone is exceeded, the trading program will be activated. Under this framework, sources that would otherwise be subject to the trading program have ***incentives to make independent reductions to avoid activation of the trading program***. We cannot discount that the 2003 309 [state implementation plan] submittal may have already influenced sources to upgrade their plants before any case-by-case BART determination under Section 308 may have required it. In addition, ***the trading program was designed to encourage early reductions*** by providing extra allocations for sources that made reductions prior to the program trigger year.[20]

---

[17] *See* Wyoming Air Quality Standards and Regulations (WAQSR) Ch. 14 Utah Admin Code R307-250-12.
[18] *See* PAC/1400, Woollums/34-5; PAC/1404, Woollums/1.
[19] *Supplement to the Technical Support Documentation for Utah's 2008 Regional Haze SIP* at 18, December 20, 2010 (available at: http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/2011-Documents/2008%20Regional%20Haze%20TSD.pdf) (provided to EPA on January 3, 2011) ("*Utah SIP Technical Support Supplement*").
[20] *Final EPA Rule on Utah SIP* at 17-18 (emphasis added).

The EPA also concluded that the SO_2 Backstop Trading Program will "achieve greater reasonable progress than would be achieved through BART" because the program "will *promote and sustain emissions reductions of SO_2* as measured against a milestone: Sources will be actively mindful of the participating states' emissions inventory and operating to avoid exceeding the milestone, *not trying to maximize their emissions to be equivalent to the milestone*[.]"[21]

In describing how the SO_2 Backstop Trading Program would achieve "better than BART" results, the Utah DEQ stated that the program "established a regulatory framework that *required* stationary sources to focus their resources on reductions in SO_2."[22] The program "locked in substantial SO_2 emission reductions, and also included allocation provisions to encourage early reduction."[23] The Utah DEQ further stated:

> 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***. * * * *
>
> ***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.[24]

The Utah PSC recently approved the Company's emissions control investments as prudent and used and useful (including the investments disputed in this case), recognizing that "the Company is required to install the pollution controls in question now in order to meet the SO_2 milestone program in the Utah Regional Haze SIP. Complying with the program is

[21] *Id*. at 18-19 (emphasis added).
[22] *Utah SIP Technical Support Supplement* at 3 (emphasis added).
[23] *Id.*
[24] *Id.* (emphasis added).

mandatory, not optional."[25] The PSC further noted that, according to the former Executive Director of the Utah DEQ, installation of emission control equipment "is necessary, not because of any decision [PacifiCorp] made, but because of the [SO_2 Backstop and Trading Program]."[26]

Question 1b: What documents in the record identify the source and effective date of the required emissions limits or pollution controls?

The required emissions limits under the SO_2 Backstop Trading Program are set forth in Utah's and Wyoming's state implementation plans (SIPs) and rules, which are publicly available documents. The SO_2 Backstop Trading Program began development in 2000 as part of the Western Regional Air Partnership (WRAP) Annex Rule,[27] which was modified after legal challenges and eventually filed in 2003 as the SO_2 Backstop Trading Program in Wyoming's and Utah's SIPs. The program was updated in both states' 2008 and 2011 SIPs,[28] and is incorporated into state administrative rules.[29]

The enforceable SO_2 emissions limits for the specific units at issue in this case are set forth in operating permits, construction permits, and approval orders provided as exhibits to testimony in this docket. The identified emission limits are effective within 90 days following the completion of the projects, as noted below:

- **Naughton Units 1 and 2**: Wyoming Air Quality Permit MD-5156[30]
  - Application submitted January 25, 2007; Permit issued May 20, 2009
  - SO_2 emissions limit – 0.15 lb/mmBtu
  - Effective date – Unit 1: June 29, 2012; Unit 2: February 9, 2012

[25] *In re Rocky Mountain Power*, Docket Nos. 10-035-124 *et al*., Report and Order at 48 (September 13, 2011) (citing to the testimony of the former Executive Director of the Utah Department of Environmental Quality).
[26] *Id*. at 49.
[27] See http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/index.htm for a summary of the history of the SO_2 Backstop Trading Program.
[28] Utah § 309 State Implementation Plan, Section XX, Regional Haze (April 6, 2011 revision), available at: http://www.airquality.utah.gov/Public-Interest/Public-Commen-Hearings/pdf-files/Jan11/SecXX%20Reg%20Haze%2012-14-10.pdf; Wyoming § 309 State Implementation Plan, Regional Haze (Jan. 7, 2011 revision), available at: http://deq.state.wy.us/EE0125BC-7633-4CD2-91FD-C2AC71CBEFF5/FinalDownload/DownloadId-0D2F7B943818E3C70AF37EA9AAE5A7F8/EE0125BC-7633-4CD2-91FD-C2AC71CBEFF5/aqd/downloads/RegionalHaze/WY_RegionalHaze309SIP%201-7-11_With%20Appendices2_CLEAN%20FINAL.pdf.
[29] *See* Utah Admin. Code Title R307; WAQSR Ch. 14.
[30] Sierra Club/105, Fisher/2, 4.

- **Hunter Units 1 and 2**: Utah Approval Order DAQE-AN0102370012-08[31]
  - Application submitted June 2006; Approval Order issued March 13, 2008
  - SO_2 emissions limit – 0.12 lb/mmBtu
  - Effective date – Unit 2: January 25, 2012; Unit 1: 2014
- **Jim Bridger Unit 3**: Wyoming Air Quality Permit MD-1552, MD-1552A[32]
  - Application submitted October 12, 2006; PermitMD-1552 issued April 9, 2007, revised permit MD-1552A issued March 16, 2009
  - SO_2 emissions limit – 0.15 lb/mmBtu
  - Effective date – July 2011
- **Dave Johnston Unit 4**: Wyoming Air Quality Permit MD-5098[33]
  - Application submitted November 7, 2007; Permit issued June 27, 2008
  - SO_2 emissions limit = 0.15 lb/mmBtu
  - Effective date – July 2012
- **Wyodak**: Wyoming Air Quality Permit MD-7487[34]
  - Application submitted March 11, 2008; Permit issued May 20, 2009
  - SO_2 emissions limit = of 0.16 lb/mmBtu[35]
  - Effective date–May 29, 2011

With the EPA's recent approval of the SO_2 Backstop Trading Program, these permits and approval orders are both state and federally enforceable.

Question 1c: What plant-specific emissions limits applied to [PacifiCorp] for the years 2006-2009?

Please see Appendix A for the unit-specific emission limits that have applied and will continue to apply PacifiCorp's 14 BART-eligible units from 2006 through 2014.

Question 1d: If the plant-specific emissions limits were exceeded, on what date would PacifiCorp be penalized for the exceedance?

Due to the nature of a regulatory enforcement action, PacifiCorp cannot provide an exact date on which penalties would be imposed. Under Utah's and Wyoming's monitoring and reporting rules, PacifiCorp is required to report any exceedance to the state;[36] the state then determines whether to assess a penalty and the amount of the penalty. If a unit-specific emissions limit established in a permit or approval order were exceeded, the Company would be

[31] PAC/2003, Teply/64.
[32] PAC/2004, Teply/127 (Permit MD-1552); PAC/2004, Teply/151 (Permit MD-1552A).
[33] PAC/2005, Teply/242.
[34] PAC/2006, Teply/118.
[35] This permit limit is a slight deviation from the 0.15 lb/mmBtu presumptive BART limit.
[36] WAQSR, Chapter 5, Section 2(g); Utah Admin. Code R307-150. *See also* 40 CFR Part 60, subpart D.

subject to penalties, possible injunctive relief, and potential citizens' enforcement suits as of the day the limit is exceeded and for every day the violation continues. Shutdown of the unit may be required to avoid penalties or due to issuance of an injunction.

The penalties for exceeding plant-specific emissions limits are severe. In Utah, exceeding the emissions limits established in an approval order subjects PacifiCorp to penalties of $7,000 to $10,000 per day per violation, which can be adjusted if the violator made or could have made reasonable efforts to prevent the violation.[37] In Wyoming, the penalty is up to $10,000 per day per violation or injunctive relief or both.[38] Federal penalties for violations of the Clean Air Act, including violations of federally enforceable permit requirements, are up to $37,500 per day per violation.[39] A permit limit exceedance is typically addressed as a state violation, but if EPA believes a state is not adequately enforcing a permit, it can seek additional penalties.[40] Another consequence for exceeding permit limits is the ability third parties to file citizens' suits seeking damages and injunctive relief under the Clean Air Act.

As discussed in response to Question 1(a) above, the Company may also be subject to penalties under the SO_2 Backstop Trading Program. Individual sources exceeding allowed emissions limits are subject to penalties for each day of the exceedance after the program is triggered.

Question 1e: On what date would PacifiCorp have to demonstrate compliance with any requirements resulting from the exceedance?

Any exceedance of a permitted emissions limit must be remedied immediately. Penalties continue for each day the limit is exceeded. Even if an enforcement action is not brought by a permitting authority for permit exceedances, penalties (assessed per day and per violation) and injunctive relief are available under the Clean Air Act's citizens' suit provisions.[41] Furthermore, if the regional milestones are exceeded and the SO_2 Backstop and Trading Program is triggered,

[37] Utah Admin.Code R307-130-2.
[38] Wyoming Stat. 35-11-901.
[39] 42 U.S.C. s. 7413(b), (d); 40 C.F.R. s. 19.4.
[40] 42 U.S.C. s. 7413(a)(2).
[41] 42 U.S.C. s. 7604.

any SO_2 emissions source that exceeds its allowance limitation is subject to a minimum penalty of $5,000 per ton of excess emissions. Each day and each ton of excess emissions is a separate violation.[42] To avoid these penalties, the exceedance must be remedied immediately.

Sierra Club incorrectly implies that a source has six years to remedy an exceedance if the trading program is triggered, but Sierra Club's witness on this topic admitted at hearing that he did not have "enough familiarity" with the program to answer questions about the alleged six-year window for compliance.[43] Sierra Club's witness also stated that he could not confirm that the penalty was $5,000 per ton.[44] The six-year window in the SO_2 Backstop Trading Program gives the *states* six years to reach the regional limit after a milestone is exceeded, but *individual sources* exceeding allowed emissions limits are subject to penalties for each day of the exceedance after a milestone is exceeded.

Question 2: Other than its PVRR(d) analysis, did Pacific Power consider any other compliance alternatives to installing the emissions controls at its BART-specific units?[45] What evidence in the record demonstrates the company's consideration of compliance alternatives such as finding an alternative generating source to meet customers' needs?

Because the results of the PVRR(d) analysis for each of the emissions control investments at issue in this case demonstrated that installation of the controls was the least-cost, adjusted for risk, option for customers as compared to the least expensive replacement power option (market purchases), it was unnecessary to conduct further analysis of compliance alternatives such as securing an alternative generating source. The Company's PVRR(d) analysis compared the known and reasonably anticipated costs of continuing to operate the units (including known and reasonably anticipated future capital investments in the units, such as

[42] *See* WAQSR, Chapter 14, Section 2 ("Each ton of SO_2 emissions in excess of a source's allowance limitation is a separate violation and each day of a control period is a separate violation."); Utah Admin. Code R307-250-12(3) ("Accordingly, a violation can be assessed each day of the control period for each ton of sulfur dioxide emissions in excess of its allowance limitation, or for each other violation of R307-250.").
[43] Tr. 185.
[44] Tr. 186.
[45] The Administrative Law Judge clarified that this question is intended to apply to the units at issue in this case.

future emissions control equipment) through the end of the units' useful lives to shutdown of the unit and replacing generating output with market purchases.

The PVRR(d) analyses were not intended to analyze the continued operation of the plant against an alternative resource. When the PVRR(d) analyses were conducted, the Company had completed the process of working with the state departments of environmental quality to determine what emissions control equipment was necessary to meet the Company's compliance obligations and necessary permits were issued. The intent of the PVRR(d) analysis was to analyze the cost-effectiveness of the emissions control equipment by comparing the costs of continuing to operate the plant through the end of its depreciable life, including known or reasonably foreseeable costs, with market purchases, the least expensive alternative source of power.[46] The cost of market purchases was used as the proxy cost for an alternative means of meeting customers' projected loads and energy needs. In each case, the PVRR(d) analysis showed that installing the emissions control equipment was the least-cost, adjusted for risk, option for customers.[47] If any of the PVRR(d) analyses had shown that installing the emissions control equipment was more costly than replacing output with market purchases, then the Company would have conducted further analyses of compliance options, including alternative resource options.

In January 2011, Sierra Club's witness, Dr. Jeremy Fisher, conducted an economic analysis of all 108 coal-fueled generating units in the jurisdiction of Western Electricity Coordinating Council (WECC). The purpose of the analysis was to estimate "the order in which existing coal plants in the [WECC] might fall out of economic merit under existing and proposed environmental regulations."[48] Dr. Fisher assumed a "worst-case scenario" for the emissions control equipment that would be required and then compared the all-in cost of operating coal-fired generation (based on 2008 EIA data) to replacement of the output with natural gas fired

[46] *Id.*
[47] *See* PAC/2000, Teply/4.
[48] PAC 2310 at 2.

combined-cycle generating plants. Even under this worst-case scenario (which assumed required installation of controls such as an SCR at plants like Naughton Unit 1, where an SCR is not required), Dr. Fisher concluded that only "[a]pproximately 5% of generation becomes economically non-meritorious relative to new [natural gas] if all environmental upgrades are required."[49]

III. ARGUMENT

A. The Company's Emissions Control Investments are Prudent and Used and Useful to Serve Customers

In this case, PacifiCorp seeks to include in rates its investments in emissions control equipment at seven of its coal-fired generating units—Naughton Units 1 and 2, Hunter Units 1 and 2, Jim Bridger Unit 3, Dave Johnston Unit 4, and Wyodak. The only issues before this Commission are (1) whether the Company's emissions control investments were objectively reasonable based on the information available at the time the decisions to invest were made;[50] and (2) whether the emissions control equipment is "presently used for providing utility service to the customer."[51] Based on mischaracterizations of the law and facts, CUB and Sierra Club assert that these investments were imprudent. CUB also contends that the emissions control equipment is not "used and useful." The substantial evidence in this case and the applicable law contradict CUB's and Sierra Club's conclusions.

CUB and Sierra Club rely primarily on four arguments.[52] First, CUB asserts—without citation to any precedent—that the Company was imprudent because it did not include an analysis of the individual emissions control investments in its IRP, and therefore did not conduct an appropriate least-cost, least-risk analysis of the investments. CUB claims that the Company

---

[49] PAC/2311 at 12.

[50] *See e.g.*, *In re PacifiCorp*, Docket No. UE 200, Order No. 08-548 at 10 (Nov. 14, 2008) ("The Commission will examine the 'objective reasonableness' of the decision."); *In re NW Natural Gas*, Docket No. UG 132, Order No. 99-697 at 52 (Nov. 12, 1999) ("In this review, therefore, we must determine whether NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.")

[51] ORS § 757.355(1)

[52] Many of CUB's and Sierra Club's arguments overlap. In responding, the Company focuses on the parties' primary positions and does not specifically identify areas of agreement between CUB and Sierra Club.

should have analyzed a "Boardman-style phase-out" for each of the units at issue in this case, and that these analyses would have shown that the investments at Naughton Units 1 and 2 and Jim Bridger 3 were not the least-cost, least-risk option.[53] CUB further argues that the Company should have re-analyzed its investment decisions as conditions changed, regardless of the timing, nature, or magnitude of the change. CUB's arguments mischaracterize the facts and applicable law and are unsupported by Commission precedent and the evidence in this record.

Second, Sierra Club belabors strained and inaccurate interpretations of applicable environmental regulations to argue that PacifiCorp had no legally enforceable compliance obligations to install the emissions control investments at the time they were installed. The simple fact is that the Company installed the emissions control equipment because it was required by federal and state regulations. The Company acted prudently by working with appropriate state authorities to develop comprehensive implementation plans for each of its facilities. These compliance plans were incorporated into the Wyoming and Utah SIPs and regional haze regulations, as well as state operating and construction permits. Sierra Club has not presented any legitimate evidence contradicting the fact that the Company had a concrete compliance obligation when it made these investments and acted prudently to develop its compliance plans.

Third, both Sierra Club and CUB assert that the Company's economic analyses of the emissions control investments were flawed and, when "corrected," do not support the cost-effectiveness of the emissions controls. To the contrary, the Company provided substantial evidence showing that the parties' proposed changes to the PVRR(d) are based on information that was not available at the time the decisions were made, are fundamentally flawed, or are immaterial to the outcome.

Finally, CUB asserts that the emissions control equipment at issue in this case is not "useful." The Company further responds to each of these arguments below.

[53] CUB Pre-Hearing Brief at 20-21.

1. *Neither the Prudence Standard nor IRP Guidelines Required that the Company Analyze its Emissions Control Investments in a Specific Manner*

It is undisputed that the legal standard for determining the prudence of PacifiCorp's emissions control investments is whether these investments were objectively reasonable based on information available at the time the decisions to invest were made,[54] and that PacifiCorp made the investment decisions in this case in 2008 and 2009. To support a finding of imprudence in this case, the evidence must show that the Company knew or should have known something in 2008 or 2009 that would cause a reasonable person not to install the emissions control equipment. This is a high standard, and the Commission recognizes that it must "exercise a high degree of caution" in a prudence review.[55]

Furthermore, the Commission has previously approved the Company's investments in emissions control equipment—made at the same time and using the same analyses as the emissions control investments in this case—as prudent in Docket UE 217.[56] Specifically, the Commission approved a stipulation concluding that the Company's investments in a dry flue gas desulfurization and baghouse system at Dave Johnston Unit 3 were prudent. These installations are exactly the same as the disputed investments at Dave Johnston Unit 4, and the Company made the decisions at Unit 3 and Unit 4 at the same time using the same analyses.[57] No party has provided any such evidence, nor do the parties assert, that the Company's technical or economic analyses in this case were somehow different from the analyses used for the investments approved in Docket UE 217.

The prudence standard does not focus on the outcome of the utility's decision or events that occur after the decision is made, but instead focuses on the objective reasonableness of the decision based on the information available at the time of decision-making. In applying the

---

[54] *See, e.g., In re PGE Request for Amortization of the Boardman Deferral*, Docket No. UE 196, Order No. 10-051 at 6 (Feb. 11, 2010) ("In a prudence review, the Commission examines the objective reasonableness of a utility's actions at the time the utility acted").
[55] *In re PGE*, Docket No. UE 139, Order No. 02-772 at 11 (Oct. 20, 2002).
[56] *See* PAC/500, Teply/50. *See also In re PacifiCorp Request for a General Rate Revision*, Docket No. UE 217, Order No. 10-472 (Dec. 14, 2010).
[57] *See* PAC/500, Teply/50, lines 3-10.

prudence standard, it is inappropriate to "let the luxury of hindsight allow [the Commission] to second guess a utility's conduct."[58] It is also inappropriate to base a prudence determination on the utility's subjective decision-making process; the prudence standard is an objective standard.[59]

Rather than applying this well-established standard, CUB's arguments focus on the subjective reasonableness of the Company's decision, asserting that a particular type of least-cost, least-risk analysis is required by the prudence standard and discarding the Company's least-cost, least-risk analysis as inadequate. CUB also repeatedly asserts that the Company was imprudent because the investments at issue in this case were not analyzed in an IRP. Each of these arguments is addressed below.

a. CUB Mischaracterizes the Prudence Standard and IRP Guidelines

CUB's argues that the Company was imprudent because it did not include the emissions control investments in its IRP, and therefore did not conduct the "correct" least-cost, least-risk analysis.[60] Contrary to CUB's arguments, the Commission has specifically rejected an interpretation of the prudence standard that focuses on the utility's "actual subjective decision making process."[61] The "Commission cannot substitute its judgment for that of the utility;"[62] if the record demonstrates, as it does in this case, that the Company's decision was objectively reasonable based on the information available at the time of the decision, the Commission must find the decision prudent.[63]

CUB's arguments also fail because there was no requirement in 2008 or 2009 that the Company analyze of each individual emissions control investment at each of its coal-fired generating units in its IRP. The role of the IRP in ratemaking decisions is explicitly limited. The IRP process provides utilities with guidance on future resource acquisition but does not address

---

[58] Order 02-772 at 11.
[59] *In re PacifiCorp*, Docket Nos. UM 995/UE 121/UC 578, Order No. 02-469 at 5 (July 18, 2002).
[60] CUB Pre-Hearing Brief at 23 (CUB claims that its "modeling shows what would have happened had PacifiCorp done the correct modeling at the correct time.").
[61] Order No. 02-469 at 5.
[62] *In re PacifiCorp*, Docket No. UE 200, Order No. 08-548 at 10 (Nov. 14, 2008).
[63] *Id.*

or decide the prudence of a utility's capital expenditures and is not intended to "usurp the role of the utility decision-maker."[64] The Commission has clearly and repeatedly stated that "[r]ate-making decisions will not be made in the Least-Cost Planning process"[65] and that acknowledgment of a utility's IRP means "simply that the plan seemed reasonable at the time the acknowledgment was given."[66]

The IRP guidelines require a utility to identify key assumptions about the future, including expected environmental compliance costs such as costs expected for CO_2, nitrogen oxides, sulfur oxides, and mercury emissions.[67] In 2007 and 2008, before the adoption of revised Guideline 8, the Commission stated that it expects "utilities to explain the basis for their compliance cost projections," but did not require individual analysis of each emissions control investment at each generating unit.[68] The Commission noted even that it did not require utilities to conduct their own studies of compliance cost projections, but could instead "rely on studies published by reliable sources."[69]

In 2008, the Commission revised IRP Guideline 8 to require more rigorous examination of environmental compliance costs, particularly potential CO_2 costs.[70] But the revised guideline still did not require a specific analysis of individual emissions control investments. The IRP guidelines in effect when the Company made the decisions at issue in this case did not require the type of analysis that CUB repeatedly contends (without citation to a single Commission precedent) was required.

No party argued—in either PacifiCorp's 2007 or 2008 IRP dockets—that the IRP guidelines required individual analysis of each of the Company's emissions control

---

[64] *In re Least-Cost Planning for Resource Acquisitions*, Docket No. UM 180, Order No. 89-507 at 6 (April 20, 1989).
[65] *Id.*
[66] *In re Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007).
[67] Order No. 07-002 at 9, 13.
[68] *Id.* at 18.
[69] *Id.*
[70] *In re Investigation into the Treatment of CO_2 Risk in the IRP Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008).

investments.[71] Both CUB and the Commission were aware of the Company's plans to install the disputed emissions control equipment before the Company filed its 2007 or 2008 IRPs. As a condition of the Commission's approval of the MidAmerican Energy Holdings Company (MEHC) acquisition of PacifiCorp in 2006, the Company agreed to Commitment 43.[72] This commitment required the Company to implement a comprehensive emissions control program, including the projects at issue in this case.[73] The Company provided annual reports to the Commission (and to CUB as a party to the stipulation supporting the MEHC acquisition) on the status and projected costs of these emissions controls from 2007 through 2010.[74]

b. The Emissions Control Investments were Consistent with the Company's Acknowledged IRPs at the Time the Decisions to Invest were Made

The Company's emissions control investments at issue in this case are consistent with the Commission-acknowledged IRPs that were in effect at the time the investment decisions were made. The Company's 2007 and 2008 acknowledged IRPs included the continued operation of the Company's coal-fueled generating plants in the preferred portfolio.[75] In the Company's 2007 IRP, the preferred portfolio included consideration of the expected costs of compliance with environmental regulations at the Company's plants and the expected costs of compliance with Commitment 43 from the MEHC merger.[76] CUB's filed comments did not address these costs.[77]

The Company's 2008 IRP included in its analysis many of the regulations at issue in this case, including potential climate change and CO_2 regulations, the National Ambient Air Quality Standards, the Regional Haze Rules, and mercury, ozone, and particulate matter (PM)

---

[71] *See* Order No. 08-232; Order No. 10-066.
[72] *In re MidAmerican Energy Holdings Co*., Docket No. UM 1209, Order No. 06-082 (February 24, 2006).
[73] This commitment ensured that the MEHC acquisition provide environmental benefits, specifically reductions in SO_2 emissions of over 50 percent, a decrease in NO_X emissions of over 40 percent, and a reduction in mercury emissions rates of almost 40 percent. PAC/1400, Woollums/34, lines 18-23.
[74] *See* Exhibit PAC/1405 for the relevant excerpts from the annual status reports in Oregon from 2007 through 2011 (See Commitment 43).
[75] PAC/1900, Woollums/2, lines 8-11. ("[T]he continued operation of these plants was part of . . . the Company's acknowledged [IRPs], and without the environmental controls at issue in this case, the plants could not continue to operate.").
[76] *See* Order No. 08-232.
[77] *See In re PacifiCorp's 2007 IRP*, CUB Opening Comments, Docket No. LC 42 (Sept. 19, 2007).

regulations.[78] The 2008 IRP specifically stated that it anticipated "spending $1.2 billion over a ten-year period to install necessary equipment under future emissions control scenarios to the extent that it's cost-effective."[79] In other words, the IRP clearly set forth the extent of the investments the Company was facing. CUB's comments on the 2008 IRP ignored these investments.

CUB also claims PacifiCorp violated IRP Guideline 8 because it did not "[bring] the clean air investments to the IRP, as anticipated by [Guideline 8]."[80] First, this position misstates the requirements of Guideline 8, as discussed above. Second, CUB's position is inconsistent with the Commission orders in the 2007 and 2008 IRPs. The emissions control investments were explicitly identified in the Company's 2008 IRP, and the Commission order acknowledging that IRP concluded that "PacifiCorp's IRP meets the current requirements under Guideline 8.[81] The Commission also specifically found that the Company's 2007 IRP met the requirements of Guideline 8.[82] Third, CUB's current position conflicts with its position in comments filed in the 2008 IRP docket, where CUB commended the Company for its sophisticated modeling of carbon risk.[83]

The 2007 and 2008 IRPs demonstrate that at the time the Company made the investment decisions in this case, neither the Commission nor CUB were advocating for the unit-by-unit modeling that CUB now contends the Company was imprudent for failing to conduct. Thus, the deficiencies CUB now claims are dispositive in this case were not identified by either the Commission or CUB at the time.

---

[78] 2008 PacifiCorp IRP at 34-37 (May 29, 2009), available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_3.pdf (last accessed on November 6, 2012).
[79] *Id*. at 37.
[80] CUB/200, Jenks-Feighner/15, lines 3-4.
[81] Order No. 10-066 at 23 (This order relied on the revised Guideline 8 from Order No. 08-339).
[82] Order No. 08-232 at 27 (issued before adoption of revised Guideline 8 in Order No. 08-339).
[83] *In re PacifiCorp's 2008 IRP*, Docket LC 47, Opening Comments of the Renewable Northwest Project and the Citizens' Utility Board at 7, 9 (Oct. 8, 2009).

c. CUB Did Not Argue that Particular Analyses of the Company's Emissions Control Investments were Required Until the Company's 2011 IRP

CUB relies on the Company's 2011 IRP Update to bolster its claim that the emissions control investments in this case were imprudent.[84] The Company disagrees with CUB's characterization of the results of the 2011 IRP Update and with CUB's reliance on the 2011 IRP Update in this case. The 2011 IRP Update is irrelevant in this case because it was prepared after the decisions at issue were made using data that did not exist at the time of decision making.[85]

The 2011 IRP docket is noteworthy for one reason—it represents the first time CUB criticized the Company's "lack of comprehensive analysis of the costs to upgrade PacifiCorp's coal plants for environmental compliance compared to the costs to retire the coal plants and invest in other resources."[86] The Company responded to these concerns by filing its IRP Coal Replacement Study.[87] The Company used stakeholder responses to the Coal Replacement Study to develop the 2011 IRP Update, which included a coal screening analysis that used the System Optimizer model to analyze the cost-effectiveness of continuing to operate the coal units under various scenarios. After working with the model's vendor, the model is now able to retire the units before the end of the units' depreciable lives. The Company is using this new modeling tool in developing its 2013 IRP and is working with stakeholders to design scenarios to address stakeholder concerns with the Company's analytics.[88] Specifically, the Company is working with CUB to develop the type of unit-by-unit analysis requested during the 2011 IRP process.

In addition to continuing to refine the analysis used in the IRP, another possible approach to the Company's future emissions control investments is for the Commission to review these investments in advance, similar to the certificate of convenience and necessity process used in

---

[84] *See* CUB Pre-Hearing Brief at 41.
[85] Order No. 02-772 at 11 ("We cannot let the luxury of hindsight allow us to second guess a utility's conduct.").
[86] Order No. 12-082 at 4.
[87] CUB refers to this as a "discredited" study. CUB Pre-Hearing Brief at 25. But this document was not intended to be an analysis; it was intended only to propose an analytical approach.
[88] Order 12-082 at 6 ("Action Item 9 was added to address the parties' concerns about PacifiCorp's coal utilization study. Pursuant to the new action item, PacifiCorp committed to host a technical workshop for stakeholders and the Commissioners to present the methodology, assumptions, and results of analysis for certain emission control investments and for Coal Replacement Study analysis for certain plants. The Company will also include a revised Coal Replacement Study in its 2011 IRP Update.").

Wyoming and the voluntary pre-approval process in Utah.[89] The Company is willing to participate in workshops with the Commission and stakeholders to develop a pre-investment review process in Oregon.

d. CUB's Reliance on the Boardman Example is Misplaced

CUB argues that the Company ignores the inherent flexibility in the Regional Haze Rules, relying primarily on PGE's decision-making process for emissions control equipment at its Boardman coal-fired generating plant. CUB argues that in December 2008, when PGE proposed an option including premature closure, PacifiCorp should have begun analyzing its investments in coal-fueled generating units in the same manner.[90] CUB ignores the fact that PGE did not decide to prematurely close the Boardman plant until 2010, and the EPA did not approve the Boardman plan until 2011, well after the investment decisions in this case were made.[91]

CUB's argument is also undercut by CUB's own statements, which describe January 2010 as the "turning point" when PGE expressed the intent to close Boardman in 2020.[92] CUB's description of the Boardman closure in 2010 conflicts with its current testimony and arguments: "Closing down a coal plant like Boardman, a baseload workhorse of a plant that produces electricity reliably around the clock is new. It could be game-changing."[93]

The argument that PacifiCorp acted unreasonably in not following PGE's Boardman model is further weakened by the fact that CUB could point to only one other example (from 2012) that is similar to Boardman.[94] In fact, as late as February 2011, CUB was still describing the Boardman closure as the "first time there had been an agreement to close a modern coal plant in the United States."[95] CUB also ignores the differences between PGE's Boardman decision

---

[89] *See* Wyoming Docket No. 20000-418-EA-12; Utah Docket No. 12-035-92.
[90] CUB/200, Jenks-Feighner/15, 21.
[91] PAC/2304; Staff/400, Colville/20; CUB/200, Jenks-Feighner/20.
[92] PAC/2304.
[93] PAC/2304.
[94] CUB/210.
[95] PAC/2307.

and the decisions facing PacifiCorp, as well as the differences between Oregon, where there is no coal production and Boardman is the only coal-fired plant, and Wyoming and Utah, where coal production and coal-fired generation are significant.[96] Even CUB admitted at hearing that the Boardman and Oklahoma examples tell us "nothing about what would happen under Regional Haze Rules in Wyoming or Utah."[97]

e. CUB's "Phase-Out" Analysis of Naughton Units 1 and 2 and Jim Bridger Unit 3 is Fundamentally Flawed

CUB argues that its "phase-out" PVRR(d) analyses for Naughton Units 1 and 2 and Jim Bridger Unit 3, based on CUB's interpretation of the Boardman phase-out plan, shows that "phasing out" these units is the least-cost, least-risk option for customers.[98] CUB adjusted the Company's PVRR(d) analysis by removing the emissions control investments and closing the unit in 2020.[99] CUB did not include alternative costs for compliance with the Clean Air Act, stating that it "did not have a basis for determining those costs" and that "with PGE that additional cost was approximately $10 million."[100]

CUB's phase-out PVRR(d) analysis is fundamentally flawed. First, CUB assumes zero dollars in environmental compliance costs through 2020, despite both of the phase-out examples cited by CUB requiring over $100 million dollars in emissions control equipment. In the Boardman example, PGE's expected costs of emissions control equipment are $140 million between 2012 and 2020 (not $10 million as CUB suggests).[101] In CUB's only other example of a "phase-out," the expected costs of emissions control equipment are $175 million between 2012 and 2026.[102]

---

[96] *See Utah Energy Fact Sheet*, *Wyoming Energy Fact Sheet*, and *Oregon Energy Fact Sheet*, available from the U.S. Energy Information Administration at http://www.eia.gov/beta/state/.
[97] Tr. 216.
[98] *See e.g.*, CUB Pre-Hearing Brief at 23.
[99] *Id.* at 29.
[100] *Id.* at 29.
[101] *See* Tr. 208-209.
[102] PAC/2308.

Second, CUB's analysis does not include any costs for decommissioning the units or any costs for a replacement baseload generation resource.[103] In the analysis supporting the Boardman "phase-out" plan, the importance of the assumptions about replacement power is emphasized: "[I]n evaluating the cost of controls associated with an option that includes plant closure, it is necessary to also include the cost associated with accelerating the replacement of the Boardman Plant's power with an alternate baseload resource."[104]

Finally, the Company's use of 20 years as the remaining useful life was consistent with EPA regulations, which require the use of a default 20-year amortization period for the remaining useful life of facilities in BART analysis: "Without commitments for an early shut down of an electric generating unit, EPA does not consider it to be appropriate to shorten the amortization period in a BART analysis."[105] Moreover, even though EPA guidance does not treat the remaining useful life as a variable, the BART discussions with the Wyoming DEQ did include consideration of additional potential regulations, like carbon regulation, that may impact the useful life of the plant.[106]

f. CUB's Argument that Re-Analysis of Investment Decisions is Required as Conditions Change, Regardless of the Timing, Nature, or Magnitude of the Change, is Meritless

CUB asserts that the Company should have re-analyzed its decisions at key decision points and milestones. Sierra Club and Staff also assert that the Company should have re-analyzed its investment decisions based on changed circumstances. The Company disagrees that re-analysis of investment decisions is required absent a significant project or market event.[107] In this case, there were no such events. Even the 2009 market price fluctuations were within the sensitivities already included in the PVRR(d) analysis.[108]

---

[103] *See* Tr. 206.
[104] PAC/2301 at 87.
[105] PAC/1400, Woollums/16-17.
[106] PAC/1400, Woollums/16.
[107] PAC/2000, Teply 12.
[108] *See* PAC/1500, Teply/26.

CUB's, Sierra Club's, and Staff's criticisms regarding re-analysis of the Company's investment decisions reflect an oversimplification of the process "to effectuate successful and timely evaluation, development, permitting and completion of these required major retrofit projects across a fleet of generation resources."[109] The process cannot be broken down into a "series of simple project implementation milestones and re-evaluation opportunities[.]"[110]

Moreover, CUB's arguments regarding updating are inconsistent. In testimony, CUB argues that PacifiCorp should have updated its PVRR(d) analysis after the initial decision but before execution of the project contract.[111] In its prehearing brief, however, CUB disavows this position and argues instead that the "prudence standard relates to what the Company expected at the time it made the decision to invest in pollution controls."[112] Thus, according to CUB, updating the PVRR(d) studies to the time the project contract was executed is "irrelevant because the contract date is not the date when the decision to invest was made, it was merely the date on which the Company acted upon that decision."[113]

Even though Staff concluded that the decision-making process here should have included updated analysis at significant project milestones, Staff nonetheless rejects CUB's position. In testimony filed in Docket UE 233 addressing the Bridger 3 scrubber, Staff testifies that "CUB advocates for what could result in decision making paralysis in response to unpredictable electricity markets and a fluid environmental regulatory situation. Paralyzed decision making would not be prudent."[114]

The quantitative evidence in this docket also demonstrates that updating the analysis as the projects progressed would not have resulted in different outcomes. For example, even with the emissions control investments at issue in this case, Naughton 1 still has a greater dispatch

---

[109] PAC/1500, Teply/10.
[110] Id.
[111] CUB/100, Jenks-Feighner/41 ("If the Company had updated its December 2008 forward price curve before executing the contract for the project in May 2009, there is a good chance that Naughton 1 would not be cost effective and Naughton 2 would have been much closer to the cost effectiveness threshold.").
[112] CUB Pre-Hearing Brief at 27.
[113] CUB Pre-Hearing Brief at 27.
[114] Docket UE 233, Staff/1201, Colville/2-3.

margin as a coal plant than it would have if it were converted to gas.[115] And when the Company updated its PVRR(d) analysis in response to CUB's and Sierra Club's criticisms, the results continued to demonstrate that installing the emissions control equipment was the least-cost, adjusted for risk, option for customers.[116]

2. *Sierra Club Mischaracterizes the Applicable Law and the Facts of This Case—Wyoming and Utah State Regulations, Plans, and Permits* Required *the Disputed Emissions Control Investments*

Sierra Club futilely attempts to establish that PacifiCorp did not have a legally enforceable obligation to install the environmental controls at issue in this case at the time they were installed. The Company discussed the applicable laws, regulations, and state implementation plans and rules in detail in its prehearing brief and demonstrated that the emissions control investments were required by legally enforceable compliance obligations.[117] Sierra Club's assertions to the contrary are based on a misunderstanding of the applicable regulations, particularly the SO_2 Backstop Trading Program.

Sierra Club's pre-filed testimony and prehearing brief is replete with mischaracterizations of the applicable law and the facts of this case. For example, Sierra Club's primary assertion is that the Company has an internal plan to line its shareholders' pockets by increasing rate base, and this "plan" is the true reason for PacifiCorp's emissions control investments, no matter how imprudent those investments may be or whether the investments are required by law.[118] This argument is absurd because it depends on the failure of the regulatory system. PacifiCorp cannot recover imprudent investments. Contrary to Sierra Club's assertions, PacifiCorp's investment decisions in this docket were based solely on its environmental compliance obligations and the actions necessary to meet those obligations at the least cost to its customers.[119]

---

[115] PAC/1500, Teply/13.
[116] PAC/500, Teply/7-38; PAC/2000, Teply/9-23.
[117] PacifiCorp Prehearing Brief at 12-21.
[118] Sierra Club Prehearing Brief at 3-6.
[119] PAC/1400, Woollums/5.

One of Sierra Club's most egregious errors is its complete misunderstanding of the SO_2 Backstop Trading Program. Sierra Club repeatedly states that the Company was not required to install SO_2 scrubbers to meet BART requirements in Wyoming and Utah.[120] This statement is extremely misleading. Wyoming and Utah require the use of BART to reduce PM emissions and NO_X emissions.[121] For SO_2 emissions, Wyoming and Utah require compliance with the SO_2 Backstop Trading Program, which requires "better-than-BART" emissions reductions.[122] Sierra Club mistakenly believes that the SO_2 Backstop Trading Program is nothing more than a "monitoring and reporting" obligation that does not create any unit-by-unit obligations until the trading program is triggered and therefore dismisses this explicit regulatory requirement as meaningless.[123] As discussed in response to the Commission's briefing questions above, Utah's and Wyoming's election to participate in the SO_2 Backstop Trading Program creates concrete and legally enforceable emissions limits at PacifiCorp's coal-fueled generating units.[124]

Despite arguing that the emissions control investments in this case were unnecessary, Sierra Club witness Dr. Fisher stated that he did not know why emissions are consistently below the milestones.[125] In fact, the milestones have been higher than actual emissions since they were first developed in 2000, and the intent of the program is to reduce emissions to remain below the milestones. Without PacifiCorp's investments in emissions control equipment, regional SO_2 emissions would have exceeded the milestones, potentially subjecting not only PacifiCorp, but also all other emitting sources in the region, to substantial penalties.[126]

Sierra Club also takes specific sentences from the Wyoming DEQ's analysis of PacifiCorp's BART applications for Wyodak and Dave Johnston out of context to argue that PacifiCorp voluntarily chose emissions control equipment that was not cost-effective. As the Company explained at hearing, however, the application analyses cited by Sierra Club were

---

[120] Sierra Club Prehearing Brief at 10-13, 23-25.
[121] PAC/500, Teply/29-30.
[122] *See, e.g.*, PAC/1901, Woollums/2. *See also* Tr. 88-89.
[123] Tr. 38-40.
[124] *See supra* pp. 4-12.
[125] Tr. 184.
[126] Tr. 37-38.

examining the cost-effectiveness of the controls based on PM emissions only, but the controls were installed to control both PM and SO_2 emissions: "[T]he only way that we could achieve the SO_2 .15 [lbs/mmBtu] emission rate at Wyodak was by the scrubber enhancement and the baghouse project. You had to do both projects together."[127]

Sierra Club's assertion that the Company takes a "piecemeal" approach to its emissions control investments is based on Sierra Club's piecemeal review of certain portions of the SIPs, statutes, regulations, permits, approval orders, BART analyses, and other documents that comprise a comprehensive approach to regional haze regulation in both Wyoming and Utah. To accurately comprehend regional haze regulations, they must be considered as a whole, including how those regulations interact and how the state implements those regulations through SIPs and permits.

3. The Company's PVRR(d) Analyses Support the Prudence of the Emissions Control Investments

The Company's decision to invest in the emissions controls at issue in this case was the result of a thorough and comprehensive decision-making process.[128] PacifiCorp developed a comprehensive strategy for assessing potentially applicable environmental regulations, involving itself in the regulatory process associated with potential regulations, and developing long-term environmental assumptions.[129] Based on the relevant environmental obligations, PacifiCorp then studies compliance alternatives to determine the cost effectiveness of identified pollution controls.[130] This analysis is performed on both an economic and operational basis to ensure the feasibility of potential controls.[131] This analysis considers reliability, capital costs, O&M costs, the life of the controls, the life of the unit itself, cost of replacement power, and other factors.[132] After reviewing the Company's compliance strategy, Staff concluded that the "Company

[127] Tr. 79.
[128] PAC/2000, Teply/4.
[129] PAC/1400, Woollums/6–7.
[130] PAC/1400, Woollums/7.
[131] PAC/1400, Woollums/7.
[132] PAC/1400, Woollums/7.

developed and is following through with a plan that attempts to manage the risk of a fluid environmental regulatory situation" and that such an approach is "reasonable."[133]

Although the Company's decision-making process for each investment included many analyses, both qualitative and quantitative, the primary economic analysis was the Company's PVRR(d) analysis.[134] This analysis calculated the PVRR(d) between two options: idling the plant and replacing the plant's output with market purchases versus installing the emissions controls. In each case, PacifiCorp's PVRR(d) analysis resulted in a positive differential—meaning it was beneficial to customers to make the emissions control investment rather than replace the generating unit.[135] As the Company demonstrated in detail in reply and surrebuttal testimony, even with the changes proposed by CUB and Sierra Club to the PVRR(d) analyses, the results still demonstrated a benefit to customers.[136]

Furthermore, the parties' disagreement with the Company's chosen variables in its PVRR(d) analyses does not demonstrate imprudence. Neither Sierra Club nor CUB argued that it was objectively unreasonable to use the PVRR(d) tool. And neither Sierra Club nor CUB demonstrated that the Company's chosen inputs were objectively unreasonable.

For example, for the Naughton units, CUB asserts that that the assumed shut down date for the PVRR(d) should have been the compliance deadline, not the year of the analysis.[137] CUB also argued that "[i]f the Company had updated its December 2008 forward price curve before executing the contract for the project in May 2009, there is a good chance that Naughton 1 would not be cost effective and Naughton 2 would have been much closer to the cost effectiveness threshold." Sierra Club voiced these same criticisms.[138] In response, the Company updated its PVRR(d) analysis (changing both the closure date and the forward price curve, as well as

---

[133] Staff/1500, Colville/30.
[134] PAC/500, Teply/21.
[135] PAC/500, Teply/37, 45, 54-55, 66-67, 76-77, 84-85.
[136] PAC/1500, Teply12-13, 16-29, 32-34, 36-37; PAC/2000, Teply/5-6, 10-13, 14-19. To avoid repetition, the Company does not further discuss its rebuttal analyses in this brief, with the exception of the Naughton example discussed below.
[137] CUB/100, Jenks-Feighner/26.
[138] Sierra Club/300, Fisher/12.

updating the final negotiated costs of the project based on information available at the time), and the results demonstrated that the emissions control investments at both units were still beneficial to customers.[139] In fact, the PVRR(d) results "would have even more strongly supported installation of the emission control equipment on the two Naughton units."[140]

CUB disavowed its earlier arguments in its prehearing brief. CUB now argues that for Naughton 1, the Company should not have updated the forward price curve before executing the contract "because the prudence standard relates to what the Company expected at the time it made the decision to invest in pollution controls, not the actual costs that were incurred after it made the decision."[141] CUB now claims "PacifiCorp is trying to move the 'decision date' to the contract signing date" so as to "capture a short-term increase in the forecasted prices."[142] In other words, in testimony CUB claimed the PVRR(d) analysis was deficient for not using the March 2009 forward price curve and, once CUB realized using this forward price curve did not change the decision to invest in emissions controls (and actually made the decision to invest more favorable), CUB now argues that PacifiCorp is trying to drive the results by using the forward price curve advocated for by CUB.

CUB and Sierra Club are also critical of the Company's use of market prices as the alternative resource.[143] However, CUB's criticism is based on its misrepresentation of the Company's position.[144] CUB argues that "PacifiCorp claims that it should have considered new generation instead of market purchases, but it did not consider that as an alternative at the time it made its decision and it did not demonstrate how that would change its flawed analysis."[145] The Company never testified that it "should have considered new generation instead of market purchases." Rather, the Company testified that the "Company's PVRR(d) analysis at the time

[139] PAC/1500, Teply.18; PAC/2000, Teply/11.
[140] PAC/2000, Teply/11.
[141] CUB Pre-Hearing Brief at 27.
[142] CUB Pre-Hearing Brief at 14-15.
[143] CUB Pre-Hearing Brief at 30; Sierra Club/100, Fisher/32.
[144] CUB Pre-Hearing Brief at 30. Note that CUB's phase-out analysis uses market prices instead of the costs of replacement generation.
[145] Id.

[of the decision] would also have typically shown that a new replacement generation resource's all-in costs were significantly unfavorable when compared to forward market price curves."[146] In other words, the Company's testimony states the exact opposite of CUB's characterization and supports the Company's use of alternative market prices because doing so was a conservative approach that would understate, not overstate, the PVRR(d) benefits of the investments.[147]

4. The Emissions Control Equipment is Used and Useful

CUB admits that the emissions control equipment at issue in this case is currently installed and being used, but disputes the usefulness of the equipment given the potential that additional controls will be required in the future to meet the regional haze rules. CUB does not, however, cite to any legal precedent for this conclusion. As discussed in the Company's prehearing brief, only a "modicum of usefulness" is necessary to meet the "useful" standard.[148] Furthermore, the absurdity of CUB's argument was demonstrated at hearing where, despite the fact that both the state of Wyoming and the EPA have declared that no further emissions control investments were necessary at Naughton Units 1 and 2 to comply with the regional haze rules, CUB refused to admit that the emissions control investments were used and useful because the EPA's decision could be appealed.[149]

B. The PCAM Proposed by PacifiCorp is Reasonable and Necessary to Address the Company's Under-Recovery of NPC, Meet the Requirements of SB 838, and Protect Customers

The Company's proposed PCAM allows the Company to collect or credit the difference between its actual NPC prudently incurred to serve Oregon customers and the amount of NPC recovered in Oregon rates, subject to a prudence review.[150] The proposed PCAM would address the Company's chronic under-recovery of NPC and would operate in conjunction with the TAM and the RAC to ensure that rates accurately reflect all of the Company's SB 838 compliance

[146] PAC/2000, Teply/5.
[147] PAC/2000, Teply/5.
[148] PacifiCorp Prehearing Brief at 12.
[149] Tr. 210-211.
[150] PAC/900, Duvall/14.

costs, both fixed and variable, as authorized by SB 838.[151] The Company's proposed PCAM also protects customers from paying for NPC that are not actually incurred by the Company.

ICNU and CUB object to implementing a PCAM for PacifiCorp.[152] Staff agrees that a PCAM is appropriate, but disagrees with the Company's proposed PCAM structure because it lacks deadbands, sharing, and earnings bands.[153] Fred Meyer Stores and Quality Food Centers, Divisions of The Kroger Co. (Kroger), argues that if a PCAM is adopted, it should allocate 70 percent of the difference between actual and forecast NPC to customers and 30 percent to the Company.[154]

1. SB 838 Significantly Increased the Risk of NPC Variability and has Contributed to the Company Under-Recovering NPC Every Year Since SB 838 was Implemented

In January 2007, before the enactment of SB 838, the Commission determined that a PCAM for PGE should "be adopted to capture power cost variations that exceed those considered part of normal business risk."[155] Since that time, SB 838 increased "normal business risk" by requiring utilities to add, integrate, firm, and shape hundreds of megawatts of new intermittent resources.[156] The new business risks created by SB 838 eclipse the "normal business risk" captured by PGE's 2007 PCAM's asymmetrical 150/75 basis point deadband.[157] Because SB 838 requires customers to bear all prudent compliance costs, the Commission should approve a PCAM without deadbands, earnings bands, or sharing bands to acknowledge both the change in risk associated with SB 838 and the assignment of that risk to customers.[158] The Company demonstrated that deadbands, earning bands, and sharing bands do not provide incentives for the

[151] The cost recovery provisions of SB 838 are codified in ORS 469A.120.
[152] ICNU/CUB Prehearing Brief at 9. CUB's testimony supported a PCAM for PacifiCorp. CUB/100, Jenks-Feighner/6-7. CUB's position changed in its joint prehearing brief.
[153] Staff Prehearing Brief at 25.
[154] FM/100, Townsend/9. Kroger also argues that direct access customers should not pay the PCAM adjustment amount if they were direct access customers during the true-up period. Pre-Hearing Brief of The Kroger Co. at 4.
[155] *Re Portland Gen. Elec. Co.*, Dockets UE 180 *et al.*, Order No. 07-015 at 26 (Jan. 12, 2007).
[156] PacifiCorp Prehearing Brief at 35-39.
[157] PAC/1800, Duvall/3-10.
[158] PacifiCorp Prehearing Brief at 35-39.

effective management of NPC, but rather function to arbitrarily reward or penalize the utility for factors outside of its control.[159]

In testimony, the Company quantified a key aspect of the increase in business risk caused by SB 838—the variance between forecast and actual wind production.[160] The Company's analysis demonstrated that since 2007, the average annual difference between actual and forecast wind generation was $35.1 million in over-forecast production—and in under-forecast system NPC.[161] Grossing up the wind generation to the 2013 forecast of wind resources demonstrates an average production over-forecast/system NPC under-forecast of $55.9 million.[162] And grossing up wind resources to the 2025 target required by SB 838 results in a production over-forecast/system NPC under-forecast of $153.4 million.[163]

This analysis demonstrates that swings in the output and value of wind generation on the Company's system substantially affect NPC and the Company's ability to recover its prudently incurred costs. This analysis is conservative because it does not consider other factors associated with integrating, firming, and shaping significant wind generation resources, such as the value of production tax credits, increasing costs of system balancing, and the decreased ability to make beneficial wholesale sales.[164] If included in the analysis, these factors would further increase the impact of variable wind production on NPC.

The Company's testimony that SB 838 has increased the risk associated with NPC recovery is supported by Standard & Poor's independent assessment of the business risks of renewable portfolio standards such as SB 838. In a report issued in March 2008, Standard & Poor's expressed concern that "the costs of RPS compliance have often not been quantified and that absorbing the full costs of RPS in retail rates could have credit implications for some companies."[165] In a 2012 report on renewable portfolio standards, Standard & Poor's stated that

[159] PAC/1800, Duvall/14-16.
[160] PAC/1800, Duvall/4-7, Tables 1-3; PAC/1801/Duvall.
[161] PAC/1800, Duvall/5.
[162] PAC/1800, Duvall//5.
[163] PAC/1800, Duvall//6.
[164] PAC/1800, Duvall/7-8; PAC/1800, Bird/5-6
[165] Exhibit PAC/2314 at 2.

"[c]ost recovery—the extent and timeliness of a utility's ability to be compensated for the costs it incurs—is key to a utility's credit quality, in our view,"[166] and emphasized that "the commissions' most important role is to authorize the provisions that enable utilities to meet [RPS] standards."[167]

While Staff conceded on cross-examination that Standard & Poor's opinion is relevant to understanding the business risks facing a utility,[168] Staff disagreed with "the horror story" Standard & Poor's presented on RPS-related business risk, opining that PacifiCorp's current wind integration charge showed that the NPC-related costs of SB 838 compliance were modest and fully addressed in rates.[169] Staff also claimed that because PacifiCorp owns the wind resources in its portfolio, it is not as exposed to RPS-related business risk.[170]

Staff's claim that wind integration costs are already fully recovered in rates is incorrect. Staff's statements ignore the Company's testimony demonstrating that all of the other wind-related cost volatility addressed in SB 838, specifically including cost volatility associated with firming and shaping wind on an annual basis, dwarfs the cost volatility of wind integration. Specifically, Staff ignores the Company's demonstration of the significant cost volatility associated with firming and shaping wind on an annual basis. No model can accurately forecast the annual volume of wind a year in advance, the 8,760 hourly wind profiles, and the associated market value of that wind each of those 8,760 hours. In fact, the Company demonstrated that hourly wind production varied from zero percent to 90 percent of total portfolio nameplate production,[171] but the TAM forecast assumes a normalized, smooth, median forecast of hourly wind production with modest variability. More specifically, five years of recorded actual history clearly demonstrates that the Company's normalized TAM forecast of total median wind production has varied as much as 15 percent from actual total annual wind production,

[166] Exhibit PAC/2315 at 3.
[167] Exhibit PAC/2315 at 4.
[168] Tr. 275.
[169] Tr. 279-280.
[170] Tr. 275.
[171] PAC/1700, Bird/4.

simultaneously with varying market prices, meaning the risk of under- or over-recovering NPC can and does vary tens of millions of dollars per year.[172] This risk will continue to grow as more wind resources are added in compliance with Oregon's RPS.[173]

Staff argues that the hour-to-hour wind volatility demonstrated by the Company does not indicate that it is impossible to accurately forecast wind on an annual basis.[174] But this claim is contrary to PacifiCorp's actual historical experience showing total annual wind production has varied from the TAM forecast by as much as 15 percent.[175] Even if the Company could perfectly forecast total wind generation on an annual basis—which is impossible—the cost to integrate, firm, and shape wind on a firm annual basis would vary from the forecast because it is impossible to accurately predict future *hourly* wind production and future *hourly* market prices.[176]

Staff's claim that wind integration costs are a small part of the Company's NPC conspicuously ignores the other large cost and risk factors acknowledged in SB 838. The Company has over 1,700 MW of owned and contracted wind generation, the operation of which cannot be reasonably predicted.[177] As a result, the Company is exposed to millions of dollars of risk above the normal business risk that existed before SB 838.[178]

Additionally, Staff's characterization of the Company's wind portfolio as largely Company-owned also ignores the facts that over 700 MW of the wind in the Company's portfolio are contracted wind resources.[179] None of the variance in these contracted wind

---

[172] PAC/1800, Duvall/5-6.
[173] PAC/1800, Duvall/5-6.
[174] Staff Prehearing Brief at 29.
[175] PAC/2200, Duvall/14-15; PAC/1801.
[176] PAC/1700, Bird/10. Contrary to Staff's suggestion, this issue is not a problem specific to the Company's GRID dispatch model—any deterministic production dispatch model would have the same issue because all deterministic models assume that forecast wind and market prices are not volatile and will balance loads and resources and optimize the system with perfect foresight. *See In re PacifiCorp 2008 TAM*, Docket No. UE 191, Order No. 07-446 at 8 (Oct. 17, 2007). Forecast NPC only captures a normalized view of the world and cannot capture the impact of changes to a year-ahead forecast of hourly weather variations in wind generation, simultaneous changes in market prices, and the resulting system impacts. PAC/2200, Duvall/16.
[177] PAC/1700, Bird/8.
[178] PAC/1800, Duvall/3-4.
[179] PAC/1700, Bird/3.

resources is reflected in the Company's NPC, and there is currently no mechanism to recover these costs. A dollar-for-dollar PCAM allows recovery of these prudently-incurred costs as authorized by SB 838. For the Company's owned resources, fixed cost recovery is provided through the RAC, but the variable costs of integrating, firming, and shaping those resources are not adequately recovered through the TAM. This result conflicts with the cost recovery provision in SB 838.

ICNU and CUB argue that NPC variations are part of normal business risk that should be borne by the utility.[180] But the change in risk associated with NPC recovery resulting from SB 838 necessitates a change in the Commission's approach to PCAMs, just as the Commission previously reevaluated the purchased gas adjustment mechanism (PGA) because "the dynamics and operation of natural gas markets have changed dramatically [since the PGA was adopted" resulting in "increased gas supply risks for shareholders . . . [that] should be recognized in modifications to the PGA mechanism."[181]

ICNU and CUB argue that the Company has not demonstrated that it is unable to recover an appropriate level of NPC.[182] ICNU and CUB ignore the Company's evidence demonstrating that its actual NPC were higher than the amount included in rates in every year since 2007.[183] Staff independently calculated the difference between actual and forecast NPC and reached similar results.[184] To argue that the Company has been recovering an appropriate level of NPC in light of this evidence is unreasonable.

---

[180] ICNU/CUB Prehearing Brief at 14. ICNU and CUB also claim that the Company has not established that lower market prices are associated with its under-recovery of NPC because the Company has not shown that market prices declined more than was forecast in rates. *Id*. at 13. They also claim that the Company ignored factors other than the addition of renewable resources, specifically the change in natural gas prices over the last five years. *Id.* To the contrary, the Company demonstrated that the combined impact of variances in wind generation and market prices resulted in a five-year average under-recovery of $35.1 million. PAC/1800, Duvall/5. The Company also explained that the addition of significant natural gas-fired generation since 2007, which is necessary to integrate, shape and firm intermittent resources, has increased the Company's exposure to the volatility of natural gas prices. PAC/1800, Duvall/10.
[181] *In re Purchased Gas Adjustment Mechanisms*, Docket No. UM 1286, Order No. 08-504 at 2, 18 (Oct. 21, 2008).
[182] ICNU/CUB Prehearing Brief at 11.
[183] PAC/900, Duvall/16 (Table 8).
[184] Staff/500, Schue/12.

2. SB 838 Requires that the Commission Address Increased NPC Recovery Risk

Staff, ICNU, and CUB argue that SB 838 does not require dollar-for-dollar recovery of all NPC.[185] The statute's plain language, however, allows the Company to recover "all prudently incurred costs associated with compliance" with the law, including integrating, firming, and shaping renewable energy sources.[186] The Company has shown that it is impossible to isolate, quantify, and accurately forecast the NPC impacts of SB 838-eligible resources[187] and that the only way to fully recover the variable costs of SB 838 compliance is with a dollar-for-dollar PCAM.

ICNU and CUB also claim that SB 838's cost recovery provision applies only to the fixed costs of renewable resources, not the variable costs.[188] One part of the cost recovery provision of SB 838 (codified at ORS 469A.120(2)) mandates authorization of an automatic adjustment clause for the recovery of the fixed costs of constructing or acquiring renewable resources and the associated transmission. But the other part of the cost recovery provision—ORS 469A.120(1)—makes it clear that recovery is not limited to fixed costs. ORS 469A.120(1) authorizes recovery of all prudently incurred costs of SB 838 compliance, including "interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs, above-market costs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers."[189]

ICNU and CUB further argue that the Company added renewable resources to its portfolio because they were the least-cost, least-risk option, not to comply with SB 838.[190] While this has been true to date, it is undisputed that these resources are being used to comply

[185] Staff Prehearing Brief at 28-29; ICNU/CUB Prehearing Brief at 9.
[186] ORS 469A.120(1).
[187] PAC/2200, Duvall/2.
[188] ICNU/CUB Prehearing Brief at 10.
[189] ORS 469A.120(1).
[190] ICNU/CUB Prehearing Brief at 12.

with SB 838, and therefore the fixed and variable costs of these resources are recoverable in rates under ORS 469A.120.

Finally, Staff argues that the Company was able to absorb its NPC under-recovery through this period without "unduly affecting earnings."[191] SB 838 does not include an earnings test and provides for recovery of all prudently incurred costs associated with compliance, not only those that must be recovered to avoid unduly affecting earnings. In addition, it is inappropriate to impose a cost recovery mechanism that will not provide the Company a reasonable opportunity to recover its prudently incurred costs under ORS 756.040.

3. The Company's Proposed PCAM Will Protect Customers Against the Risk of Paying NPC that the Company Did Not Actually Incur

ICNU and CUB claim PacifiCorp's PCAM will harm customers by guaranteeing the Company's ability to recover NPC.[192] ICNU and CUB fail to even attempt to explain why customers are harmed by paying for the cost of service—indeed, that is the foundation of rate regulation. Moreover, the Company's proposed mechanism benefits customers by ensuring customers pay no more than the costs incurred to serve them. This benefit is not hypothetical; PGE's actual NPC have been lower than its forecast NPC in every year but one since 2007.[193] Under the deadbands and earnings bands in PGE's PCAM, this has resulted in PGE retaining approximately $63.5 million that would be refunded under PacifiCorp's PCAM proposal, while customers have received refunds of only $22 million.[194] In a scenario where actual NPC are less than forecast, Staff acknowledged that deadbands and sharing bands can "give the Company a windfall when it has done nothing right."[195]

ICNU and CUB claim that PGE's experience of forecast NPC exceeding actual NPC since the enactment of SB 838 contradicts PacifiCorp's argument that renewable resources have

[191] Staff Prehearing Brief at 33.
[192] ICNU/CUB Prehearing Brief at 14.
[193] Tr. 258-259.
[194] Tr. 263-264.
[195] Staff/1400, Schue/25.

caused the Company to under-recover NPC.[196] In fact, PGE's experience reinforces the Company's position that SB 838 has led to increased volatility in NPC and increased difficulty in accurately forecasting NPC. For PacifiCorp, these factors have resulted in under-forecasting NPC; for PGE, these factors have resulted in over-forecasting. This dynamic illustrates why it is fair to utilities and to customers to have a dollar-for-dollar PCAM in the current environment.

ICNU and CUB also argue that SB 838 has not affected the Company's ability to recover NPC because the Company's under-recovery has remained relatively constant over the past five years, and was higher in 2007 when the Company had few wind resources.[197] To the contrary, the amount of the Company's under-recovery has increased since 2007, from approximately $112 million in system NPC to over $135 million.[198]

4. The Application of a Deadband, Sharing Mechanism, and Earnings Band is Unwarranted, Redundant and Would Perpetuate PacifiCorp's History of NPC Under-Recovery

ICNU, CUB, and Staff propose alternative PCAMs that include a deadband, earnings band, and sharing. There is no policy justification for application of any of these components, let alone all three in one mechanism. Moreover, no party presented any evidence as to how the imposition of deadbands, sharing bands, and earnings bands would provide an incentive for the Company to procure fuel and power more prudently or at a lower cost. In fact, the Company provided evidence that such mechanisms are incapable of doing so. Without a nexus, there is no rational basis for the Commission to impose such mechanisms to deny the Company any reasonable opportunity of recovering its costs of serving customers. While ICNU and CUB argue that PacifiCorp's proposed PCAM is "unprecedented," PacifiCorp's proposal is consistent with the majority of PCAMs in the country. PGE is the only company in PacifiCorp's cost of capital peer group with a PCAM that includes all three components.[199] More importantly, the parties' proposals would do nothing to address NPC over- or under-forecasts except in the most

[196] ICNU/CUB Prehearing Brief at 12.
[197] ICNU/CUB Prehearing Brief at 12.
[198] PAC/900, Duvall/16, Table 8.
[199] PAC/900, Duvall/32; PAC/901/Duvall; PAC/2200, Duvall/10. *See also* PacifiCorp Prehearing Brief at 39.

extreme circumstances. The Company would have recieved zero percent of its unrecovered NPC if the parties' proposed mechanisms had been in effect from 2007 through 2011.[200]

a. The Parties' Proposed Deadband is Unreasonable and Requires the Company to Absorb Too Much Risk

Staff, ICNU, and CUB propose an asymmetric deadband that would disallow recovery between 150 basis points above to 75 basis points below the Company's authorized ROE.[201] This proposal is based on the deadband that was adopted for PGE's PCAM in 2007, which was $22.8 million/$11.4 million when adopted and was revised in 2010 to a dollar-defined deadband of $30 million/$15 million.[202] For PacifiCorp (as of 2011), the same 150/75 basis point deadband would be considerably larger: $43.2 million/$21.6 million.[203] As discussed earlier, the deadband in PGE's 2007 PCAM was sized for "normal business risk," and this deadband would be fully offset by the increase in business risk that occurred with the passage of SB 838.[204]

b. The Commission's Analysis in PGE's PCAM Docket Undermines the Parties' Proposed Deadband

As the Company explained in its prehearing brief, it is inappropriate to apply the 2007 PGE PCAM deadband to PacifiCorp for many reasons: (1) in every year since 2007, the proposed deadband would have precluded recovery of any unrecovered NPC, even though PacifiCorp's unrecovered NPC was more than $25 million in four of the five years and no party has alleged that the Company's NPC were imprudent; (2) because the deadband is basis-point-based, it expands as the Company's rate base grows to incorporate new resources required by SB 838;[205] (3) PGE's 2007 PCAM was redesigned in 2010 to a dollar-defined deadband; (4) the 2007 PCAM was "narrowly tailored to suit PGE;" and (5) PGE's 2007 PCAM does not reflect the additional business risk resulting from SB 838.[206]

---

[200] PAC/1800, Duvall/11-12, Table 4.
[201] ICNU/CUB Prehearing Brief at 17; Staff Prehearing Brief at 25.
[202] *In re PGE*, Docket No. UE 215, Order No. 10-478 at 10 (Dec. 17, 2010).
[203] PAC/1800, Duvall/13.
[204] PacifiCorp Prehearing Brief at 38; PAC/1800, Duvall/7.
[205] Since 2007, the Company has made $1.6 billion in wind investments, which increased rate base and the dollar equivalent of any basis point deadband. PAC/1800, Duvall/3.
[206] PacifiCorp's Prehearing Brief at 40-43.

In addition, the Commission's rejection of alternative deadband proposals in the 2007 PGE case undermines the parties' proposed deadbands here. In that case, which was decided before SB 838, the Commission rejected a basis point deadband proposed by CUB with the dollar equivalent of approximately $38 million/$19 million, and adopted a basis point deadband with the dollar equivalent of $22.8 million/$11.4 million.[207] No party has explained why it is rational or fair to apply the 2007 PGE PCAM precedent to PacifiCorp to produce deadbands of $43.2 million/$21.6 million—or almost double what the Commission found to be a reasonable deadband in 2007, pre-SB 838, and even higher than the deadband that the Commission rejected in that case.[208]

c. Sharing is Not Appropriate Because the Evidence Shows that Most NPC Components are Outside the Company's Control

ICNU and CUB propose a 75/25 sharing of costs outside the deadband, with the Company absorbing 25 percent of costs.[209] Staff proposes 90/10 sharing, with the Company absorbing 10 percent of NPC outside of the deadband.[210] CUB originally agreed that 90/10 sharing was appropriate, but has since adopted ICNU's view.[211] Kroger advocates 70/30 sharing, but no deadband.[212] The parties claim that sharing is necessary to provide the Company with an incentive to minimize NPC.[213] The Company has shown, however, that nearly all NPC components are out of the Company's control, including wind generation capacity and market prices.[214] Variations in customer loads, hydro generation, and the timing of forced outages also have a significant impact on NPC, and the Company cannot control these factors either.[215] PacifiCorp is effectively operating with sharing band that requires the Company to bear 100 percent of the risk unrecovered NPC, giving PacifiCorp the greatest possible incentive to

[207] Tr. 269-270.
[208] PAC/1800, Duvall/13; Tr. 273-274.
[209] ICNU/CUB Prehearing Brief at 20.
[210] Staff Prehearing Brief at 25.
[211] ICNU/CUB Prehearing Brief at 20.
[212] FM/100, Townsend/9.
[213] Staff Prehearing Brief at 35; ICNU/CUB Prehearing Brief at 20.
[214] PAC/1800, Duvall/7; PAC/2200, Duvall/19.
[215] PAC/2200, Duvall/19.

minimize NPC. Despite this incentive, PacifiCorp has incurred approximately $134 million of prudently incurred NPC on behalf of customers since 2007, without compensation, while taking all possible measures to mitigate this risk to the Company. This history aptly demonstrates that PacifiCorp cannot reasonably control large cost exposures which are volatile and inherently outside of the control of the Company, therefore this is a misplaced incentive and reasonable cause for the Commission to strongly consider a more appropriate mechanism.

In response, Staff concedes that "most of the Company's power cost operational decisions result in small changes in NPC,"[216] which is inconsistent with Staff's claim the Company has enough control over NPC to warrant a sharing mechanism. Staff also dismisses the Company's position that a prudence review encourages the Company to keep NPC low as "unduly negative."[217] The Company's position is not "negative"; it simply reflects the reality that the Company must always be prepared to demonstrate that its costs are objectively reasonable.

ICNU and CUB recommend a larger deadband than the 90/10 band applied to PGE because of complaints about PacifiCorp's TAM[218] and the fact that PacifiCorp is a multi-jurisdictional utility.[219] These factors bear no relationship to the design of PacifiCorp's PCAM, nor do they provide any rationale for imposing higher cost-sharing percentages on PacifiCorp.[220]

e. The Parties' Proposed Earnings Bands Serve to Further Reduce the Company's Ability to Recover Its Prudently Incurred NPC, Including Costs of SB 838 Compliance

On top of a deadband and sharing, Staff, ICNU, and CUB propose an earnings band that would result in no adjustment if the Company's earnings are within 100 basis points of the Company's authorized ROE.[221] An earnings band may result in the disallowance of prudently

---

[216] Staff Prehearing Brief at 35.
[217] *Id*.
[218] ICNU/CUB Prehearing Brief at 20.
[219] ICNU/CUB Prehearing Brief at 20.
[220] Idaho Power Company, with the majority of its load outside of Oregon, has a sharing band of 90/10. PAC/1800, Duvall/17.
[221] Staff Prehearing Brief at 25; Joint ICNU-CUB Prehearing Brief at 19.

incurred costs associated with compliance with SB 838 and should therefore be rejected.[222] Additionally, the earnings band proposed in this case effectively functions as a back-up deadband, increasing the normal business risk assigned to the utility. For all of the reasons discussed above, the Commission should not adopt deadbands or earnings bands in PacifiCorp's PCAM given the increased NPC-related business risks PacifiCorp now faces, including the risk associated with accurately forecasting NPC in rates.

5 The Commission Should Not Reduce the Company's Cost of Capital if the Company's Proposed PCAM is Adopted

ICNU and CUB argue that the Company should reduce its cost of capital if it receives a dollar-for-dollar PCAM.[223] The parties, however, agreed to settle the issue of rate of return in the partial stipulation filed in this docket on July 12, 2012. The Company had proposed a dollar-for-dollar PCAM in its direct filing in this case, before the parties entered into the rate of return stipulation. It is inappropriate for ICNU and CUB to undermine the parties' stipulation by proposing a change to the rate of return. Moreover, the vast majority of PCAMs for utilities in the Company's cost of capital peer group do not contain deadbands, sharing mechanisms, or earnings review deadbands.[224] This indicates that the Company's cost of capital, which is set based on an analysis of the Company's risk as compared with similar companies, already accounts for the effect of a dollar-for-dollar PCAM on the Company's risk and any further adjustment would be unreasonable.

6. The Commission Should Reject ICNU and CUB's Proposal to Cap Collections

ICNU and CUB argue that the Company's collections should be capped at six percent because ORS 757.259(8) applies such a cap to deferrals of electric utilities.[225] In the 2007 PGE order, the Commission found that it had applied this cap to similar deferrals, but did not find that the cap applies as a matter of law.[226] The Company requests that the Commission not apply this

---

[222] *See* PacifiCorp's Prehearing Brief at 38.
[223] ICNU/CUB Prehearing Brief at 15-16.
[224] PAC/2200, Duvall/10; PAC/900, Duvall/31-32; Exhibit PAC 901.
[225] ICNU/CUB Prehearing Brief at 21.
[226] Order No. 07-015 at 27.

cap to the Company's PCAM. For the reasons set forth above and in the Company's prehearing brief, SB 838 provides for timely recovery of prudently incurred costs associated with compliance. Limiting the Company's ability to timely recover these costs by imposing an amortization cap is contrary to SB 838.

7. The Company Agrees that a PCAM Should Not Apply to Direct Access Customers

ICNU and CUB argue that a PCAM should not apply to direct access customers.[227] Kroger argues that direct access customers should not pay the PCAM adjustment amount if they were direct access customers during the true-up period.[228] The Company agrees with Kroger's position.

C. The TAM Is Necessary to Update NPC for the Benefit of Customers and the Company and Should Not be Eliminated or Modified

ICNU and CUB argue that the TAM should be eliminated or substantially modified because there is no need for an annual power cost update, especially if the Commission adopts a PCAM for PacifiCorp, and the TAM has been prejudicial to customers.[229] Staff disagrees and argues that annual filings are necessary to ensure NPC are set to match actual costs as accurately as possible.[230] Kroger argues that if the TAM is eliminated, it should be replaced with a mechanism that does not impede the ability of customers to choose direct access.[231]

The facts do not support ICNU and CUB's position that the TAM is unnecessary or harmful. First, a key objective of the TAM is "to update the forecast net power costs to account for changes in market conditions."[232] The Commission has previously recognized that "it is important to update the forecast of power costs included in rates to account for new information"

---

[227] ICNU/CUB Prehearing Brief at 21.
[228] Pre-Hearing Brief of The Kroger Co. at 4.
[229] ICNU/CUB Prehearing Brief at 24.
[230] Staff Prehearing Brief at 36.
[231] Prehearing Brief of The Kroger Co. at 2. Kroger also proposes that PacifiCorp's direct access program be modified to allow customers to transition over a five-year period to a cessation of the transition adjustment. Kroger noted that this issue may be further explored in Docket UM 1587, and the Company agrees that it is outside the scope of this docket.
[232] *In re PacifiCorp 2009 Transition Adjustment Mechanism*, Docket UE 199, Order No. 09-274, Appendix A at 9 (July 16, 2009); PacifiCorp's Opening Brief, Docket UE 245.

and that "[i]f the forecast is not updated each year, then [the utility] will be exposed to more than normal business risk."[233] At hearing, ICNU acknowledged that there is nothing per se harmful to customers in basing NPC in rates on the most recent available information.[234] All energy utilities in Oregon have an annual power cost update or annual natural gas update, and ICNU and CUB failed to present any reason why PacifiCorp alone should not annually update its NPC.

Second, the TAM is necessary to set accurate and fair transition adjustments for direct access. Once the TAM is eliminated, ICNU proposes to set the transition adjustment using updated market prices, but potentially outdated NPC.[235] At hearing, ICNU acknowledged that using this approach could result in a transition adjustment that would allow direct access customers to avoid a sharp run-up in market rates and shift that entire cost increase to retail customers.[236] While ICNU was open to reinstating the TAM if many customers elected direct access,[237] this response would come too late to prevent a windfall to direct access customers and a cost-shift to cost-of-service customers if market prices changed significantly from one year to the next. Allowing such a result is antithetical to the Commission's well-established policy on direct access.[238] It is unreasonable to eliminate the TAM without any serious consideration of how direct access will be managed without it.

Third, it is unreasonable to assert that the TAM harms customers when customers pay significantly less than actually incurred NPC since the TAM's adoption.[239] Moreover, with the TAM, the Company avoided general rate cases for the 2008, 2009, and 2012 rate periods.[240]

Fourth, the TAM provides advantageous treatment of new resources for customers by allowing customers to receive the variable cost/dispatch benefits of a resource through the TAM,

---

[233] Order No. 07-015 at 8.
[234] Tr. 236.
[235] Tr. 232.
[236] Tr. 233-234
[237] Tr. 234.
[238] *In re PacifiCorp*, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).
[239] *In re PacifiCorp 2013 TAM*, Docket No. UE 245, PacifiCorp Opening Brief at 10 (Sept. 14, 2012); PAC/900, Duvall/16; Pac/1800, Duvall/10, 12 (Table 4).
[240] *In re PacifiCorp 2013 TAM*, Docket No. UE 245, Reply Brief at 4 (Sept. 21, 2012); Docket UE 227, Surrebuttal Testimony of Andrea L. Kelly, PPL/800, Kelly/3, lines 1-3. The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).

even if fixed costs are not yet included in base rates.[241] For example, customers received the variable benefits of PacifiCorp's Lake Side 545 MW gas resource for two full years (through the 2008 and 2009 TAMs) before Lake Side's fixed costs were recognized in rates in UE 210.[242] And the 2013 TAM reflects the benefits of the Mona-to-Oquirrh transmission project,[243] even though parties have challenged the recovery of the fixed costs of this project in this case.[244]

Fifth, the TAM also benefits customers by synchronizing rate treatment of the fixed costs and variable benefits of new renewable energy resources, providing customers the beneficial variable cost impacts of new wind resources in NPC at the same time that customers are required to pay the fixed costs through the RAC. Without the TAM, customers would not receive the variable benefits of new wind resources until the Company files a general rate case, even when customers are already paying the fixed costs of these resources through the RAC.[245]

If the Commission does not eliminate the TAM, ICNU and CUB argue that the Commission should modify the process to limit the Company's ability to increase NPC when overall costs have not increased.[246] None of ICNU and CUB's proposed modifications are warranted.

ICNU and CUB argue that PacifiCorp should not be allowed to change TAM rates if the Company's ROE is within 100 basis points of its authorized ROE.[247] But ICNU's witness Mr. Deen acknowledged that this proposal was not supported by his testimony, and he was not prepared to defend the proposal at the hearing.[248] Because ICNU's witness was unable to

---

[241] Tr. 225; *In re PacifiCorp 2010 TAM*, Docket No. UE 207, Order No.09-432 (2010) (customers will receive the variable cost/dispatch benefits of a new resource on-line by April 1, even if the Company waits to file a general rate case to address the fixed costs).
[242] *In re PacifiCorp's 2009 TAM*, Docket No. UE 199, Exhibit PPL/300, Kelly/7 and PPL/302. The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).
[243] In the GRID workpapers for the 2013 TAM, the Mona-to-Oquirrh transmission line is reflected in a 700 MW increase in transmission capacity in May 2013.
[244] ICNU/100, Deen/23-24.
[245] Tr. 227-228.
[246] ICNU/CUB Prehearing Brief at 28.
[247] *Id.*
[248] Tr. 247.

explain this proposal and no party filed any testimony supporting it, there is no evidence in the record to assess the proposal. The Commission should therefore reject it.

ICNU and CUB argue that the TAM should be modified to update non-NPC-related revenues,[249] require additional evidentiary support for changes to GRID or other new issues,[250] and eliminate the final TAM update.[251] In each case, the TAM Guidelines—which ICNU and CUB helped develop—already fully address the issues.[252] With respect to the final update, ICNU admits that the TAM Guidelines have narrowed the scope of TAM updates and created a number of additional procedural safeguards.[253] The TAM Guidelines have been in place only for the most recent TAM filings. The Company urges the Commission to allow the parties to continue to use and perfect the provisions in the TAM Guidelines, rather than prematurely declare them unworkable.

D. The Commission Should Approve the Separate Tariff Rider for the Company's Mona-to-Oquirrh Transmission Project

To appropriately match recovery of the costs of the Mona-to-Oquirrh transmission project with the benefits that the project will provide to customers, the Company proposes recovering its investment in the project through a separate tariff rider that will go into effect after the project goes into service during 2013. In addition to ensuring the appropriate matching of costs and benefits, the Company's proposal meets even the strictest interpretation of the used and useful standard because the project's costs will not be included in rates until the project is being used to serve customers.

---

[249] ICNU/CUB Prehearing Brief at 28.
[250] *Id.*
[251] *Id.*
[252] The TAM Guidelines address changes in loads by allowing for an update of NPC-related revenues annually associated with the TAM. *In re PacifiCorp's 2009 TAM*, Docket No. UE 199, Order No. 09-274, TAM Guidelines at Section D (4). The TAM Guidelines also address how PacifiCorp can propose changes to the GRID model and its inputs. Order No. 09-274, Appendix A at 9, Section A.1 of the TAM Guidelines. The TAM Guidelines prohibit the Company from including changes to its model in a standalone TAM if Staff, CUB, or ICNU objects. *Id.* And the TAM Guidelines require the Company to provide workpapers and supporting documentation with each round of TAM filings. Order No. 09-274, Appendix A at 15, Attachment B to the TAM Guidelines.
[253] Tr. 237. The final update process allows for discovery, notice of potential objections, the Company's response to objections, the ability of a party to propose additional process to resolve the matter if necessary, and the ability of a party for file for deferral of a cost challenged by the parties.

ICNU, CUB, and Staff oppose the Company's proposal to recover the costs of the Mona-to-Oquirrh transmission project through a separate tariff rider. These parties rely on three primary arguments: (1) the project will not be in service when the rates approved in this case go into effect on January 1, 2013, and therefore is not "used and useful" under ORS 757.355; [254] (2) the delay in recovery of the costs is just a question of regulatory lag;[255] and (3) the Company is cherry-picking cost items for recovery in rates without including offsetting revenues.[256] As discussed in detail in the Company's prehearing brief, these three arguments are meritless. To avoid repetition, the Company includes only a brief summary of its responses to these arguments.

First, under the Company's proposal, the Mona-to-Oquirrh transmission project will be in service, and therefore "presently used for providing utility service to the customer,"[257] before the costs of the project are included in customer rates through a separate tariff rider.[258] Second, contrary to the parties' arguments, regulatory lag is not a "regulatory principle" nor does it "bar" the Company's recovery of its investment; regulatory lag is a consequence of traditional rate regulation that fails to match the provision of service with the costs of providing that service.[259] This failure is particularly problematic when the used and useful standard is applied strictly to bar recovery of capital investments completed during a future test period. The Company's proposal complies with the used and useful standard but avoids unnecessary delay of costs incurred to serve customers. Finally, the Company is not "cherry-picking" items for rate recovery without consideration of offsetting revenues. Because the prudence of the investment was presented in this general rate case—where all elements of the calendar year 2013 test period revenue requirement were subject to review—any concerns about selectively choosing items for rate recovery are unfounded.[260] Furthermore, the Company's proposal is consistent with the

[254] *See* Staff Prehearing Brief at 24; ICNU/CUB Prehearing Brief at 3.
[255] Staff Prehearing Brief at 25; ICNU/CUB Prehearing Brief at 5.
[256] ICNU/CUB Prehearing Brief at 3-4; Staff Prehearing Brief at 25.
[257] ORS § 757.355(1)
[258] PacifiCorp's Prehearing Brief at 51-53.
[259] PacifiCorp's Prehearing Brief at 56-58.
[260] *Id.*

treatment of the Mona-to-Oquirrh transmission project in the NPC forecast in the Company's 2013 TAM.

In their joint prehearing brief, ICNU and CUB also make three additional claims. First, ICNU and CUB argue that the Company is "seeking approval of its costs before they have been completed."[261] In fact, despite PacifiCorp specifically including the costs of the Mona-to-Oquirrh transmission project in the 2013 test period where they could be considered in proper context, ICNU and CUB refused to review the costs because the project is "not yet complete and should not be considered in this case."[262] This argument is inconsistent with current Commission practice. The forecast test period includes projects expected to be completed before the rate effective date, which means that utilities routinely seek and receive recovery of projects that are not "complete" when the costs are reviewed and recovery is approved.[263]

Second, ICNU and CUB argue that Commission precedent related to PGE's Coyote Springs facility illustrates the "dangers of allowing non-operational facilities to go into rates without proper review, "[264] leading ICNU and CUB to "strongly caution against preapproval of non-operational facilities."[265] But this case does not involve "preapproval" of PacifiCorp's investment in the Mona-to-Oquirrh transmission project or a lack of "proper review." The stipulating parties, including ICNU and CUB, agree that the Company's decision to build the project was prudent. ICNU and CUB's refusal to review the costs of the project is not the equivalent of a lack of "proper review." Not only did the Company provide sufficient information about the costs to allow for full review, but the Company also agreed that the project's final costs will be audited and reviewed for prudence before being included in customer rates.[266]

---

[261] ICNU/CUB Prehearing Brief at 8.
[262] *Id.*
[263] PAC/1600, Dalley/7.
[264] ICNU/CUB Prehearing Brief at 7.
[265] *Id.* Note that PacifiCorp discussed the Coyote Springs precedent, as well as other applicable Commission precedent, in its prehearing brief at pages 53 to 56.
[266] Partial Stipulation, ¶ 14. The Company agrees with CUB and ICNU that the partial stipulation does not include an "agreement on the prudence of the overall amount of expenditures for [the Mona-to-Oquirrh] project." ICNU/CUB Prehearing Brief at 8.

Finally, ICNU and CUB argue that "there is no reason to allow PacifiCorp to obtain early approval of the costs of the Mona-to-Oquirrh transmission line that was built in and for Utah customers, especially when the overall costs have not [been] verified."[267] As discussed in the Company's testimony and prehearing brief, the Mona-to-Oquirrh transmission project has benefits that extend beyond Utah.[268] The project is necessary to maintain the Company's compliance with mandated North American Electric Reliability Corporation and WECC reliability and performance standards.[269] The project also strengthens the overall reliability of PacifiCorp's transmission system, mitigating the risk of customer outages and load curtailments.[270] In addition, the project allows the Company to continue to meet native load obligations in all of its states (not just Utah) and to continue to meet contractual obligations to third parties under its OATT.[271] These benefits were recognized by Commission Staff in PacifiCorp's most recent IRP, which was acknowledged by the Commission.[272] Furthermore, and as discussed above, the costs will be reviewed and verified before being included in rates.

In conclusion, the Commission should approve PacifiCorp's request to recover its investment in the Mona-to-Oquirrh transmission project when the project goes into service during 2013 because: (1) the project will be used and useful before being included in customer rates; (2) the necessity and benefits of the project were acknowledged in PacifiCorp's 2011 IRP; (3) the Company's proposal is consistent with Commission precedent; (4) the stipulating parties agree that the decision to build the project was prudent; and (5) the final costs of the project will be audited and reviewed for prudence before being included in customer rates.

---

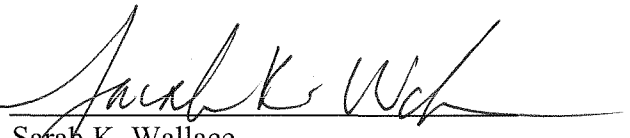
[267] ICNU/CUB Prehearing Brief at 31.
[268] PacifiCorp's Prehearing Brief at 49-50; PAC/700, Gerrard/2, 9-14, 16-21.
[269] PAC/700, Gerrard/2, 18-22.
[270] *Id*. at 12, lines 5-8.
[271] *Id.* at 13, lines 16-19.
[272] *In re PacifiCorp 2011 Integrated Resource Plan*, Docket LC 52, Staff's Final Comments and Recommendations at 41-42 (October 13, 2011). The Commission acknowledged the IRP in Order No. 12-082.

IV. CONCLUSION

As demonstrated in this brief, as well as PacifiCorp's prehearing brief and pre-filed testimony, the Company has presented substantial evidence supporting a Commission order:

- Authorizing inclusion in rates of the Company's investments in emissions controls at seven of its coal-fired generating units because these investments are necessary to comply with applicable environmental regulations, prudent, and used and useful to serve customers.
- Approving a PCAM that allows full recovery—no more, no less—of the difference between the Company's forecast and actual NPC to address the Company's chronic under-recovery of NPC, to comply with SB 838, and to mitigate the risk of customers paying more NPC than the Company actually incurred.
- Rejecting proposals to eliminate or modify the Transition Adjustment Mechanism.
- Authorizing the Company to file a special tariff rider that allows inclusion in rates of the Company's investment in the Mona-to-Oquirrh transmission project to begins serving customers in 2013.
- Approving and adopting the uncontested partial stipulation between the Company, Staff, the CUB, ICNU, and Kroger because it results in fair, just, and reasonable rates for PacifiCorp's Oregon customers.

Respectfully submitted this 7th day of November, 2012.

By: 

Sarah K. Wallace
Senior Counsel
PacifiCorp d/b/a Pacific Power

Katherine McDowell
McDowell, Rackner & Gibson

Attorneys for PacifiCorp