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October 4, 2012

VIA ELECTRONIC FILING
AND COURIER DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
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Attn: Filing Center

Re: UE 246 – PacifiCorp's Prehearing Brief

PacifiCorp d.b.a. Pacific Power hereby submits for filing an original and five (5) copies of its Prehearing 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 / AS

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Vice President, Regulation

Enclosures

cc: UE 246 Service List

CERTIFICATE OF SERVICE

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of

PACIFICORP d/b/a PACIFIC POWER's

Request for a General Rate Revision.

PACIFICORP'S
PREHEARING BRIEF

OCTOBER 4, 2012

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of PACIFICORP d/b/a PACIFIC POWER's Request for a General Rate Revision.	**PACIFICORP'S PREHEARING BRIEF**

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully submits this prehearing brief in accordance with the Administrative Law Judge's May 30, 2012 prehearing conference memorandum. Because a partial settlement has been reached in this case, only three issues remain for the Public Utility Commission of Oregon's resolution: (1) the recovery of the Company's investments in emissions controls at some of its coal-fired generating plants; (2) the Company's proposed power cost adjustment mechanism (PCAM); and (3) the appropriate timing of the Company's recovery of its investment in the Mona-to-Oquirrh transmission project. The evidence in this case supports a Commission order that:

- Authorizes recovery of the Company's investments in emissions controls at its coal-fired generating plants because these investments are necessary to comply with applicable environmental regulations, prudent, and used and useful to serve customers.
- Approves a PCAM that allows full recovery—no more, no less—of the difference between the Company's forecast and actual net power costs (NPC) to address the Company's chronic under-recovery of NPC and to comply with Senate Bill (SB) 838.
- Authorizes the Company to file a special tariff rider that allows recovery of the Company's investment in the Mona-to-Oquirrh transmission project to begin when the project is placed in service in 2013.
- Approves and adopts the uncontested partial stipulation between the Company, Commission Staff, the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and the Kroger Co. because it is reasonable and results in fair, just, and reasonable rates for PacifiCorp's Oregon customers.

In this case, PacifiCorp presented substantial evidence showing that its investments in emissions controls at its coal-fired generating plants are prudent, cost-effective, and currently used to provide service to PacifiCorp's customers. The parties' arguments to the contrary are based on misinterpretations of the applicable legal standards and after-the-fact changes to the Company's economic analyses. These arguments are contrived to promote a specific policy agenda—ending the Company's use of coal-fired generation. But this case is not about stakeholder's policies regarding coal-fired generation. This case is about the objective reasonableness of the Company's decisions based on the information it knew or reasonably should have known at the time the decisions were made. The Company's emissions control investments are necessary to comply with existing environmental regulations and allow continued operation of these generation resources, and the Company's economic analyses show that the investments were cost-effective for customers based on the information available at the time of the decision to invest. The Commission should therefore allow full recovery of these emissions control investments because the investments are prudent and used and useful to serve customers.

The Company also presented substantial evidence demonstrating that a PCAM is necessary to address the Company's chronic under-recovery of NPC, thereby allowing PacifiCorp to recover prudently incurred costs under ORS 756.040, and to recover the prudent costs of compliance with SB 838,[1] Oregon's renewable portfolio standard (RPS). PacifiCorp's proposed PCAM is designed specifically for PacifiCorp's diverse generation portfolio and unique operations, and recognizes the significant changes in "normal business risk" caused by SB 838.

[1] Codified in ORS Chapter 469A.

In response, the parties argue that the Commission should adopt a PCAM similar to Portland General Electric Company's (PGE) 2007 PCAM (which has since been modified) and Idaho Power Company's PCAM. But PacifiCorp is different than PGE and Idaho Power, and circumstances have changed since those PCAMs were adopted. Those PCAMs were adopted with deadbands and earnings bands requiring the utility to bear "normal business risk associated with actual net power costs varying from forecast."[2] PacifiCorp's proposed PCAM recognizes that SB 838 increased PacifiCorp's "normal business risk" by at least as much as the deadbands and earnings bands included in PGE's and Idaho Power's PCAMs.

Since SB 838 was enacted in 2007, PacifiCorp has added 1,400 MW of new wind resources to its generation portfolio and certified 300 MW of hydro as low-impact hydro under SB 838.[3] PacifiCorp's proposed PCAM addresses the increased challenges of system operations and NPC forecasting with this new fleet of intermittent resources. A PCAM with dollar-for-dollar recovery of prudent NPC ensures that neither the Company nor its customers will be unfairly enriched or harmed by normal and prudent NPC variances, which should also help to minimize controversy around modeling NPC in rates. For these reasons, the Commission should adopt the Company's proposed PCAM.

Finally, the Company has shown that it is appropriate to allow recovery of the Company's investment in the Mona-to-Oquirrh transmission project through a separate tariff rider that will become effective once the project goes into service during the calendar year 2013 test period. The parties to the partial stipulation filed in this case did not contest the prudence of the Company's decision to build the Mona-to-Oquirrh transmission project, and the final costs of the project will be audited and reviewed for prudence before being included

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[2] *In re PGE*, Docket Nos. UE 180/184, Order No. 07-015 at 18 (Jan. 12, 2007).
[3] PAC/1700, Bird/2-3.

in rates. Thus, the only issue for the Commission's resolution is the *timing* of the Company's recovery of its investment.

The Company's proposal ameliorates any concern about the project being "used and useful" at the time recovery begins in rates and appropriately balances the costs borne and the benefits received by customers. The Company's proposal ensures timely recovery of an investment in a transmission line that has been reviewed and acknowledged as part of the integrated resource planning process and is necessary to continue providing safe, reliable, and adequate service to its customers. 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—the parties' concerns about selectively choosing items for rate recovery are unfounded. The Commission should therefore approve the Company's proposed tariff rider, to be effective once the Mona-to-Oquirrh transmission project is in service.

In addition, PacifiCorp requests that the Commission approve and adopt the partial stipulation between the Company, Commission Staff, the Citizens' Utility Board of Oregon (CUB), the Industrial Customers of Northwest Utilities (ICNU), and Fred Meyer Stores, LLC and Quality Food Stores, divisions of The Kroger Co. (Kroger). This partial stipulation is a reasonable resolution of all of the other issues in this case and results in rates that are fair, just, and reasonable.

II. BACKGROUND

On March 1, 2012, PacifiCorp filed a request to revise its schedules of rates and charges for electric service in Oregon, effective January 1, 2013. The proposed revised rates reflected an Oregon-allocated revenue requirement increase of $38.4 million, or 3.2 percent. As a result of resetting Schedule 299 (the Rate Mitigation Adjustment or RMA) to reflect forecast customer loads by rate schedule, the proposed increase to net rates was $41.2 million, or 3.5 percent. This case is based upon an historical base period of the 12 months ended June 2011, with normalizing and pro forma adjustments to calculate a calendar year 2013 future test period. With one exception—the Mona to Oquirrh transmission project—the Company's request included capital additions that were in service or would be in service before December 31, 2012. The Company's case also included a request for approval of a dollar-for-dollar PCAM to annually true-up forecast NPC to actual NPC.

Commission Staff, CUB, ICNU, the Sierra Club, and Kroger actively participated in this case, filing opening testimony on June 18 and 20, 2012, and rebuttal testimony on August 13, 2012. The Company filed reply testimony on July 19, 2012, and surrebuttal testimony on September 5, 2012. A hearing is scheduled for October 15 and 16, 2012, and oral argument is scheduled for November 30, 2012.

III. PARTIAL STIPULATION

After settlement conferences in May and June 2012, the Company, Staff, CUB, ICNU, and Kroger (collectively, the Stipulating Parties) reached a settlement of many of the issues in this case. A partial stipulation memorializing the settlement was filed on July 12, 2012, and testimony in support of the stipulation was filed on August 1, 2012. Sierra Club did not oppose the partial stipulation. The Stipulating Parties agree to:

- An overall revenue requirement increase of $20.7 million, to be effective January 1, 2013.[4] As a result of resetting the RMA (Schedule 199) to

[4] Partial Stipulation, ¶ 8, Exhibit A; Joint Testimony in Support of Partial Stipulation ("Joint Testimony") at 4; Staff Testimony in Support of Partial Stipulation at 1-4. *See also* PAC/1000/Wilson (labor costs); PAC/1100/Dalley (revenue requirement).

reflect forecast customer loads by rate schedule, the increase to net rates is $23.5 million, or approximately 2.0 percent.[5]

- For Oregon regulatory purposes, the following cost of capital:[6]

Component	Structure	Cost	Weighted Cost
Long-term Debt	47.60%	5.322%	2.533%
Preferred Stock	0.30%	5.427%	0.016%
Common	52.10%	9.800%	5.106%
	100.00%		7.655%

- The inclusion in Oregon rates of the accelerated depreciation and decommissioning costs for the early retirement of the Company's Carbon thermal generating plant in 2015.[7]

- The prudence of the Company's investment in the Black Cap solar resource.[8]

- The Company filing a request for deferred accounting to defer Oregon's allocated share of the incremental revenues from the Company's Open Access Transmission Tariff associated with the Company's pending rate case at the Federal Energy Regulatory Commission (Docket No. ER11-3643-000), beginning January 1, 2013, and continuing until the revenues are included in Oregon rates.[9]

- The prudence of the Company's decision to build the Mona-to-Oquirrh transmission project. If the Commission approves the Company's tariff rider, the parties will have the opportunity to review the actual costs of the project and to challenge costs that are not properly assigned to the project or are imprudent, or costs exceeding the amount included in the Company's initial filing ($380.6 million total company; $12.6 million maximum revenue requirement impact, Oregon-allocated).[10]

- The rate spread and rate design set forth in Exhibit D and E to the partial stipulation. Most customer rate schedules, including residential service, large general service, and agricultural pumping service, will see a 2.2 percent rate increase.[11]

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[5] Partial Stipulation, ¶ 15, Joint Testimony at 9. *See also* PAC/1300, Griffith/7-10, PAC/1303, Griffith/Table 1303-3 (RMA).
[6] Partial Stipulation, ¶ 10; Joint Testimony at 4; Staff Testimony in Support of the Partial Stipulation at 4-7. *See also* PAC/200/Hadaway (cost of equity); PAC/300/Williams (cost of debt; capital structure); Staff/200/Storm (capital structure; cost of equity); Staff/300/Muldoon (cost of debt); ICNU/200/Gorman (capital structure; cost of equity).
[7] Partial Stipulation, ¶ 11, Exhibit B; Joint Testimony at 5. *See also* PAC/500, Teply/87-92.
[8] Partial Stipulation, ¶ 12; Joint Testimony at 5. *See also* PAC/800/Griswold.
[9] Partial Stipulation, ¶ 13; Joint Testimony at 5-6. *See also* ICNU/100, Deen/6-7.
[10] Partial Stipulation, ¶ 14(c), Exhibit C; Joint Testimony at 7-9. *See also* PAC/ 700/Gerrard (Mona-to-Oquirrh generally); PAC/1106/Dalley (Mona-to-Oquirrh revenue requirement—revised in Exhibit C to the Partial Stipulation and in PAC/1601/Dalley); PAC/1304, Griffith/1-3 (illustrative tariff at page 3).
[11] Partial Stipulation, ¶16, Exhibits D and E; Joint Testimony at 9-10. *See also* PAC/1300/Griffith (rate design and rate spread).

The Stipulating Parties further agree that the rates resulting from the partial stipulation meet the standard in ORS 756.040 and represent a fair and reasonable compromise of the settled issues.[12] The Stipulating parties therefore recommend that the Commission adopt the partial stipulation and include its terms and conditions in the Commission's final order in this case.[13]

IV. ARGUMENT—CONTESTED ISSUES

As a result of the partial settlement, only three issues remain for the Commission's resolution. (1) the recovery of the Company's investments in emissions controls at some of its coal-fired generating plants; (2) the Company's proposed PCAM; and (3) the appropriate timing of the Company's recovery of its investment in the Mona-to-Oquirrh transmission project. The Company addresses each of these issues in detail below.

A. Emissions Controls

The Company's request in this case includes recovery of its investments in emissions control equipment at its coal-fired generating plants, including Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3. These emissions control investments are necessary to comply with existing environmental regulations and are currently installed and operating to reduce emissions at these facilities.

There are two questions before the Commission regarding the Company's emissions control investments. The first is whether the Company's emissions control investment decisions were prudent. The prudence standard requires the Commission to review whether the Company's decisions were objectively reasonable given the information it knew or reasonably should have known at the time it made the decisions.[14] In making the decision to

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[12] Joint Testimony at 11.
[13] Joint Testimony at 12.
[14] *See, e.g., In rePacifiCorp, dba Pacific Power*, Docket Nos. UM 995/UE 121/UC 578, Order No. 02-469 at 5 (July 18, 2002).

invest in emissions control equipment at these generating facilities, the Company's foremost concern was its obligation to provide safe, reliable, and cost-effective service to its customers. The Company also needed to maintain compliance with all applicable laws, regulations, and regulatory agency orders. For each of the emissions control investments at issue in this case, state and federal laws and regulations required the Company to install the emissions controls. The Company could not continue serving its customers with these units if the investments were not made within the applicable compliance deadlines. In addition, the Company performed detailed emissions control technology reviews and a present value revenue requirement differential (PVRR(d)) analysis for each of the emissions control investments and determined that installing the controls and continuing to operate the unit was the least cost, adjusted for risk, option to meet the Company's obligation to serve its customers.[15]

The Company has presented substantial evidence that it prudently analyzed the cost-effectiveness of its investment decisions and prudently planned its compliance with a multitude of regulations in an ever-changing regulatory environment. Furthermore, it is undisputed that the Company prudently managed the installation of the emissions control equipment and actively managed project costs, in some cases resulting in significant cost reductions.

The second question before the Commission is whether the emissions controls are presently used to provide service to customers; in other words, are the controls used and useful? The answer to this question is yes. All of the emissions controls and associated ancillary equipment and installations at issue in this case are currently in service and

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[15] As discussed further below, the state regulatory authority (not the Company) ultimately decides which emissions control equipment is selected as the "Best Available Retrofit Technology."

operating to reduce emissions or otherwise perform their designated function at the facilities. The reductions in emissions provided by the emissions controls are a benefit to customers. The emissions controls and associated equipment and installations are therefore used and useful to serve customers.

CUB and Sierra Club argue that the Company's investment decisions were not prudent, basing this argument primarily on alleged flaws in the Company's PVRR(d) analyses. None of the alleged flaws in the Company's PVRR(d) analysis (which the Company rebutted in detail in its reply and surrebuttal testimony) support a finding that the Company's decisions were objectively reasonable. CUB and Sierra Club's arguments are nothing more than a disagreement with the Company's approach, based on the belief that their suggested changes to the PVRR(d) result in a "better" analysis (a conclusion largely dependent on using hindsight to second guess the Company's approach).

Sierra Club also asserts that the Company was imprudent because there was no federally enforceable requirement to install these controls. This argument ignores the Company's extensive evidence on the *state-enforceable* compliance obligations that required installation of these emissions controls. The Company also demonstrated that, given these obligations, the process for and timing of the install-ations was reasonable and prudent.

The Company extensively analyzed its compliance obligations, actively worked with regulators to develop its compliance alternatives, coordinated installation of the controls with the Company's existing four-year outage cycle to reduce replacement power costs, reduced impacts on the Company's system as a whole given the number of units affected by the applicable regulations and mitigated rate impacts by managing the additional costs of the emissions control investments (within its compliance obligations) across those units, and prevented increased costs to complete construction caused by insufficient resources and unfavorable market conditions associated with "just-in-time" installation schedules as the compliance deadline approached.[16] The Company also conducted analyses of the available technologies and the associated cost-effectiveness of those technologies to allow the state regulatory authority to determine the "Best Available Retrofit Technology" before making the final decision to proceed with installing the required controls. The fact that CUB and Sierra Club now claim these actions are imprudent reveals the true motive behind their assertions—closing coal-fired generating units. It is not appropriate, however, to make policy decisions to reduce reliance on coal-fired generation during this prudence review.

1. Applicable Legal Standards

a. The Prudence Standard

Prudence is "determined by the reasonableness of [a utility's] actions 'based on information that was available (or could reasonably have been available) at the time.'"[17] The prudence standard is objective:

> [T]he Commission will examine the "objective reasonableness" of the decision. The Commission will consider the decision at the time it was made, with no hindsight. The Commission cannot substitute its judgment for that of the utility. The determination of what is reasonable is the primary responsibility of utility management, not this Commission.[18]

[16] CUB argues that a prudent utility would analyze every emissions control investment using the "Boardman" model. But PGE's decision-making regarding the Boardman facility was not found to be reasonable until 2010, after the Company's investment decisions in this case and well after preparation of the Company's analyses of the emissions control equipment in this case. PAC/1900, Woollums/3. *See also* PAC/1400, Woollums/37-38.
[17] *In re PGE*, Docket No. UE 102, Order No. 99-033 at 36-37 (Jan. 27, 1999). *See also In re Northwest Natural Gas*, 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.").
[18] *In re PacifiCorp, dba Pacific Power*, Docket No. UE 200, Order No. 08-548 at 10 (Nov. 14, 2008).

Because the standard is objective, contemporaneous evidence of the Company's decision-making process is not required, and a utility is not required to prove the factors that it actually considered in making its decision:

> [I]f the record demonstrates that a challenged business decision was objectively reasonable, taking into account established historical facts and circumstances, the utility's decision must be upheld as prudent even if the record lacks detail on the utility's actual subjective decision making process."[19]

In applying the prudence standard, the Commission does not focus on the outcome of the utility's decision and consistently refuses to "let the luxury of hindsight allow us to second guess a utility's conduct."[20] The Commission also recognizes that the prudence standard is a high standard:

> It is important to note that, in a prudence review, the Commission must exercise a high degree of caution. We recognize the need for regulatory certainty, and, consequently, must use a high standard when examining the reasonableness of a utility's actions."[21]

Thus, under the Commission's prudence standard, it must uphold PacifiCorp's emissions control investment decisions as prudent if the decisions were objectively reasonable based on the information available at the time the decisions were made.

b. The Used and Useful Standard

The used and useful standard requires that utility property be "presently used" for providing utility service to be included in customer rates:

> [A] public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation of real or personal property not presently used for providing utility service to the customers.[22]

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[19] *In re PacifiCorp dba Pacific Power*, Docket Nos. UM 995/UE 121/UC 578, Order No. 02-469 at 5 (July 18, 2002).
[20] *In re PGE*, Docket No. UE 139, Order No. 02-772 at 11 (Oct. 30, 2002).
[21] *Id*.
[22] ORS § 757.355(1).

The determination of whether utility property is presently used to provide utility service to customers is generally straightforward. For example, a generating plant is "used" when it begins generating power that is transmitted through the transmission and distribution system.[23]

Although not specifically mentioned in the statute, utility property must also be "useful" to be included in rate base. The Commission has interpreted this to mean that the property must provide a benefit to customers, although this benefit can be limited.[24] The Commission requires only a "modicum of usefulness" to distinguish property from being "merely used."[25] For example, the Commission has found that additional reserves and increased flexibility provided by a generating plant were a benefit and were "useful" despite being of "negligible value."[26]

2. Existing Environmental Regulations Required Installation of the Emissions Control Equipment

The emissions control investments at issue in this case were made to comply with existing environmental regulations.[27] The intervenors attempt to distract the Commission from this basic—but critical—point with irrelevant and incorrect arguments. But the fact remains that PacifiCorp had compliance obligations that it needed to meet for the plants to continue operating. In making the decision to invest in emissions control equipment to meet these obligations, the Company's focus is:

> [M]aintaining a reasonable balance between protecting the interests of customers, meeting the obligation to serve the current and reasonably projected demands of our customers, and

[23] *In re PGE*, Docket No. UE 21, Order No. 84-898 (Nov. 14, 1984).
[24] *Id.*
[25] *Id.*
[26] *Id.*
[27] PAC/1400, Woollums/2-3.

> complying with environmental regulations, all in the face of an uncertain regulatory environment.[28]

Air quality regulation in the United States is constantly evolving and can be hard to predict given shifting public policy and frequent and lengthy litigation. In addition, air quality regulation is unique because: (1) the states play a prominent role in the implementation and enforcement of federal regulations; (2) air quality laws are often the subject of decades-long litigation; and (3) most air quality standards are reviewed and updated periodically, in some instances every five to ten years. This complex and shifting regulatory environment complicates the Company's investment decision-making process. These investment decisions are made even more difficult by the fact that the decisions must be made as early as five years in advance if significant construction or extended outage periods are needed to complete such retrofits.

In this case, the environmental regulations requiring the installation of the emissions control investments are the Regional Haze Rules and National Ambient Air Quality Standards (NAAQS), which the EPA adopted to implement the federal Clean Air Act.[29] The Company also expects some of the emissions control equipment to support compliance with regulations such as the Mercury and Air Toxins Standards (MATS) recently finalized by the Environmental Protection Agency (EPA).[30]

Because air quality regulation in the United States is so complex, with overlapping and ever-changing requirements, the specific regulations at issue in this case are discussed in more detail below, beginning with a brief discussion of the Clean Air Act.

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[28] PAC/500, Teply/4.
[29] *Id.* at 3.
[30] *Id.*

a. Description of the Relevant Environmental Regulations

(1) Clean Air Act

Under the Clean Air Act (CAA), the EPA is charged with implementing and enforcing a number of different programs that are intended to improve national air quality and protect human health.[31] In general, the federal CAA programs are implemented by individual states through the development of State Implementation Plans (SIPs), as well as through issuance of air quality permits.[32]

An important and unique component of the CAA is its allocation of authority between federal and state jurisdictions. As noted above, under the CAA, once the EPA sets emissions or technology limits or requirements under different CAA programs, the states implement the different programs through their SIPs. While the CAA and the EPA set forth the goals and basic requirements of the SIPs, "the states have broad authority to determine the methods and particular control strategies they will use to achieve the statutory requirements."[33] SIPs are required to include enforceable emissions limits, including schedules and timetables for compliance.[34] SIPs are required to include an enforcement program[35] and are enforceable by the issuing state.[36] SIPs must be submitted to the EPA for approval. The EPA has the ability to issue a federal implementation plan if it believes a particular state SIP is not adequate, but

[31] *See* 42 U.S.C. § 7401(b)(1).
[32] *See* 42 U.S.C. § 7410.
[33] *BCCA Appeal Grp. v. EPA*, 355 F.3d 817, 822 (5th Cir.2003) (citing *Union Elec. Co.*, 427 U.S. at 266, 96 S.Ct. 2518).
[34] *Id.* § 7410(a)(2)(A).
[35] *Id.* § 7410(a)(2)(B)-(C); *See also* 40 C.F.R. § 51.160(a) ("[E]ach plan must set forth legally enforceable procedures that enable the State or local agency to determine whether the construction or modification of a facility, building, structure or installation, or combination of these will result in—(1) A violation of applicable portions of the control strategy; or (2) Interference with attainment or maintenance of a national standard in the State in which the proposed source (or modification) is located or in a neighboring State.").
[36] *Id.* § 7410(c)(3).

states are granted considerable discretion under the CAA, and a state can enforce its SIP even before EPA approval of the SIP.[37]

The SIP is typically implemented through state laws and regulations and the issuance of construction and operating permits (referred to as Title V permits), which incorporate all of the relevant controls and emission limits for each source.[38] Permits issued under Title V of the CAA must include enforceable emissions limitations and a schedule of compliance.[39] In addition, the permit may include a permit shield, meaning that compliance with the permit is deemed compliance with applicable provisions of the CAA.[40]

(2) Regional Haze Rules

In 1999, EPA first promulgated rules to address haze obscuring national parks and other wilderness areas in the United States. Certain aspects of that rule were vacated by the D.C. Circuit Court in 2002.[41] In 2005, EPA adopted a new rule re-addressing the vacated aspects of the rule. The revised Regional Haze Rules became effective on September 6, 2005.[42]

The Regional Haze Rules require states to submit SIPs to address regional haze visibility impairment in 156 federally protected parks and wilderness areas.[43] These areas are known as "mandatory Class I Federal Areas" or simply "Class I" areas. The goal of the regional haze program is to attain natural visibility conditions by the year 2064. The first phase of the rule requires certain stationary sources put in place between 1962 and 1977 to comply with Best Available Retrofit Technology (BART) to reduce visibility-impairing air

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[37] *See State of Texas, et al. v. U.S. EPA*, No. 10-60614, August 13, 2012 (5th Cir.).
[38] *See* 42 U.S.C. § 7661.
[39] *Id*. § 7661(a).
[40] *Id*. § 7661(f).
[41] *See American Corn Growers Ass'n v. EPA*, 291 F.3d 1 (D.C. Cir. 2002).
[42] *See* 40 C.F.R. Part 51.
[43] *See* 42 U.S.C. § 7472(a).

pollutants. Visibility-impairing pollutants include sulfur dioxide (SO_2), nitrogen oxide (NO_x), and particulate matter (PM). The Regional Haze Rules set an emissions threshold for the application of BART at 250 tons emitted per year. The facilities that meet this threshold are referred to as BART-eligible facilities. Each state is then required to determine which BART-eligible facilities emit air pollutants that may reasonably be anticipated to cause or contribute to impairment of visibility in a Class I area.[44] These facilities are referred to as "subject to BART."

BART determinations are required for any source that a state deems "subject to BART." In making BART determinations, states must consider five factors set forth in section 169A(g)(7) of the CAA: (1) the costs of compliance; (2) the energy and non-air-quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[45] These five factors must be applied on a source-by-source basis. In this case, state environmental regulators applied these factors to determine that the emissions control investments were necessary.

States were required to incorporate the Regional Haze Rules into their SIPs and submit them to the EPA for approval no later than December 17, 2007.[46] The SIPs are required to include a long-term strategy for minimizing regional haze in each Class I area within the state. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress

[44] 40 C.F.R. § 51.308(d)(3)(iv).
[45] *See also* 40 CFR 51.308(e)(1)(ii).
[46] 40 C.F.R. § 51.308(b).

goals established by states having Class I areas.[47] The Regional Haze Rules contemplate review and progress reports every five years.[48]

The Regional Haze Rules include the BART mandate, as well as a regional alternative. Specifically, the rules allow states to implement an emissions trading program or other alternative compliance measure so long as that alternative would achieve "better than BART" results.[49] This provision was included in the original rule promulgated in 1999. As a result, in the late 1990s a regional body of nine western states known as the Western Regional Air Partnership (WRAP) was formed to implement the Regional Haze rule on a regional basis. Through the WRAP, the Company worked with states, tribes, and federal agencies to develop and implement regional planning processes to comply with regional haze requirements.[50]

(3) National Ambient Air Quality Standards

The CAA charges the EPA with setting NAAQS, which set maximum permissible levels of certain criteria pollutants in the ambient air.[51] Through lengthy processes, EPA designates "nonattainment" areas where the level of pollutant exceeds the NAAQS.[52] Primary NAAQS are to be attained as expeditiously as practicable, but not later than five years after designation of an area as a nonattainment area.[53] Currently, EPA sets NAAQS for sulfur oxides, particulate matter, carbon monoxide, ozone, nitrogen oxide, and lead. The CAA requires that NAAQS be reviewed periodically, which involves a lengthy scientific review followed by a rulemaking process. States are required to submit modified SIPs to

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[47] *Id.* § 51.308(d)(3).
[48] *Id.* § 51.308(g).
[49] 40 C.F.R. § 51.308(e)(2).
[50] PAC/500, Teply/5.
[51] *See* 42 U.S.C. § 7409(a)-(b).
[52] *See* 42 U.S.C. § 7407(d).
[53] 42 U.S.C. §7410(a)(1).

EPA within three years of each new or revised NAAQS.[54] In addition, when a source applies for construction permits, the state requires the source to demonstrate compliance with the NAAQS through air dispersion modeling. In permitting emission control projects, the Company was required to conduct air dispersion modeling that concluded that the NAAQS for SO_2 were not being met in a specific area, resulting in an additional driver for the emission control projects at Naughton Units 1 and 2.

(4) Mercury and Air Toxics Standards

Under section 112 of the CAA, the EPA sets national emissions standards for Hazardous Air Pollutants (HAPS). Standards are set categorically by source, and existing sources falling within a list of regulated source categories must use Maximum Achievable Control Technology (MACT) to reduce the pollutants. For pollutants for which standards have not yet been established, MACT is set on a case-by-case basis by the permitting authority, usually the state.[55] In 2000, the EPA formally added coal plants to the list of source categories for regulation of mercury emissions. Over the next decade, EPA's regulation of mercury from coal plants was the subject of extensive litigation, and in 2008 the D.C. Circuit vacated EPA's attempt at regulation of mercury emissions, which was called the Clean Air Mercury Rule.[56] In late 2009, the EPA began a process to develop air toxics emissions standards. Finally, in 2012, the EPA formally issued the MATS, establishing MACT standards for coal plant mercury emissions, in addition to standards for acid gas and non-mercury metal emissions. Affected power plants must comply with the MATS within

[54] *See* 42 U.S.C. §7410(a)(1).
[55] *See* 42 U.S.C. 112(g)(2)(A).
[56] *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

three years of the rule's effective date; this establishes a compliance deadline of April 16, 2015.[57]

b. State Implementation of the Regional Haze Rules and NAAQS

The emissions controls at issue in this case were installed at power plants in Wyoming and Utah. In Wyoming, CAA programs are administered and enforced by the Air Quality Division of the Wyoming Department of Environmental Quality. The Air Quality Division issues operating permits under Title V of the CAA for each of the Company's coal-fueled power plants located in that state. Permits are also required for certain construction activities and modifications to existing sources. The permits set forth all of the applicable CAA and state requirements. Operating permits may be modified over time based on changing standards or environmental conditions. Following the adoption of federal Regional Haze Rules, both Utah and Wyoming began to reevaluate how they would implement regional haze and BART requirements.

In June 2006, the Wyoming Air Quality Division published draft BART rules, notified the Company that it was in the process of developing a regional haze SIP, and requested that the Company conduct an analysis of BART options at each of its plants deemed subject to BART for SO_2, NO_x, and PM.[58] In addition, the Wyoming Air Quality Division noted that it was in the process of developing mercury control requirements, further noting that the control strategies for regional haze compliance may overlap with the mercury requirements and suggested that the Company may wish to consider this fact in developing BART control strategies.[59] Final BART rules were adopted by the Wyoming Air Quality

[57] 40 C.F.R. § 63.9984(b).
[58] PAC/1901/Woollums.
[59] *Id*.

Board on December 5, 2006.[60] Wyoming also submitted revisions to its SIP to the EPA in 2008 and 2011.

In Utah, the CAA is implemented and enforced by the Utah Department of Environmental Quality Division of Air Quality. Under the Utah SIP, the Division of Air Quality issues operating permits under Title V of the CAA. In 2008, the Air Quality Board adopted revisions to the Utah SIP to meet the requirements of the revised Regional Haze Rules and addressed BART requirements for NO_x and PM. For SO_2, the Utah SIP sets forth a Regional Milestone and Backstop Trading Program that sets compliance milestones for the years 2008 through 2018.[61]

Both Wyoming and Utah use a "permit shield" provision, which means that compliance with the conditions of the permit will be deemed compliance with any applicable requirements as of the date of permit issuance.[62]

c. Company Involvement in Rule and Permit Development

All of the above-described SIP, rule, and permit development processes are public. EPA actions in developing rules are conducted under the federal Administrative Procedures Act notice and comment rulemaking. State actions such as the issuance of permits, rule development, and SIP development are all subject to public review and comment. Given the significant potential impact of environmental regulations, the Company participates extensively in both the state and federal processes.

The Company's involvement in the regulatory process is extensive and typically includes submitting comments on proposed rules, participating in stakeholder groups, and providing oral testimony in public hearings. In addition, because many of the units the

[60] PAC/1903/Woollums.
[61] Utah State Implementation Plan Section XX p.27 (April 6, 2011).
[62] WAQSR Ch. 6. Sec 3(k); Utah Admin. Code R307-415-6f.

Company operates have different characteristics or already have environmental controls installed, the Company works closely with the states to develop construction and operating permits that are tailored to the particular unit. This process also allows the Company to advocate for lower-cost compliance controls where available. As an example of its efforts to advocate for lower-cost compliance controls, the Company appealed certain conditions of its BART permits for the Jim Bridger and Naughton plants.[63]

The Company's level of involvement in the environmental regulatory process has two primary benefits: (1) it allows the Company to be in a position to assess potential impacts of proposed rules as they are developing and begin planning accordingly; and (2) it offers the Company an opportunity to advocate for environmental regulations and compliance terms that are effective yet practicable and sensible for the Company and its customers.

3. The Company Prudently Analyzed Compliance Alternatives, Cost Effectiveness, and Benefits of the Emissions Control Investments

The Company owns (at least in part) and operates 19 coal-fired generating units, 14 of which have been designated as BART-eligible units under the Regional Haze Rules.[64] The seven units with emissions control investments contested in this case have also been deemed to be "subject to BART." As noted above, from 2006 through 2008, Utah and Wyoming finalized their regional haze rules and revised their state SIPs to implement the EPA's 2005 Regional Haze Rules. Under the law, the Company is required to comply with these rules as expeditiously as practicable, but no later than five years from the date of EPA approval of the state SIPs. The Regional Haze Rules required SIP submissions by December

[63] *Appeal and Petition for Review of BART Permits*, Docket No. 10-2801, Wyoming Environmental Quality Council (Feb. 26, 2010).
[64] PAC/500, Teply/6.

2007 and EPA action on those SIPs within 18 months of submission.[65] Utah and Wyoming submitted their revised SIPs to the EPA in early 2008 with the underlying assumption of a 2013 compliance deadline.

To meet this 2013 compliance deadline, the Company worked with state regulators from 2006 through 2009 to determine BART for the Company's affected units, including analyses of the Company's options for complying with the Regional Haze Rules at each unit. The analyses also considered future state and federal mercury control requirements, some of which overlapped with BART.

The Company's analyses evaluated alternative technologies for their ability to economically achieve compliance and support and integrated approach to control criteria pollutants. Among other considerations, the analyses: (1) reviewed available retrofit emissions control technologies, including performance and cost metrics; and (2) reviewed capital costs on a dollars-per-ton of pollutant removed basis (as required as part of BART determinations) and costs for projected improvement in visibility.[66] For each unit subject to BART, the respective state regulatory authority identified the appropriate control technology to achieve what the air quality regulators determined were cost-effective emissions reductions.[67] Once the state regulatory authority identified the required BART technology, the Company proceeded with its competitive bidding process.

The particular emissions control equipment installed at each unit is described in detail in the Direct Testimony of Chad A. Teply (PAC/500). Mr. Teply identifies the applicable environmental regulations, the state permit requiring the specific emissions control equipment, the targeted pollutants, and the capital costs of the emission control equipment.

[65] 42 U.S.C. §7410(k).
[66] PAC/500, Teply/22-23.
[67] PAC/500, Teply/23.

This information is summarized in the table below for the Commission's convenience.

Mr. Teply also discusses the analyses conducted for each unit, which include: (1) a 2005 study of NO_x emission reduction technology conducted by Sargent and Lundy (Naughton Units 1 and 2, Dave Johnston Unit 4, Wyodak, and Jim Bridger Unit 3);[68] (2) BART analyses for Naughton Units 1 and 2, Dave Johnston Unit 4, Wyodak, and Jim Bridger Unit 3 conducted by CH2M Hill in 2007; (3) and a flue gas desulfurization (FGD) upgrade study conducted by Sargent and Lundy for Hunter Units 1 and 2.[69]

Naughton Unit 1[70]		
	Wet Flue Gas Desulfurization System	**Low NO_x Burners**
Targeted Pollutant(s):	SO_2, PM	NO_x
Date of Permit Issuance	May 2009 (Permit MD-5156)	December 2009 (Permit MD-6042)
Compliance Deadline	2013	December 31, 2012
Date of Contract Execution	May 2009	January 2010
Construction Start Date:	2010	2012
In-Service Date:	June 2012	June 2012
Total Cost:	$121 million	$9 million

Naughton Unit 2[71]		
	Wet Flue Gas Desulfurization System	**Low NO_x Burners**
Targeted Pollutant(s):	SO_2, PM	NO_x
Date of Permit Issuance	May 2009 (Permit MD-5156)	December 2009 (Permit MD-6042)
Compliance Deadline	2013	June 1, 2012
Date of Contract Execution	May 2009	January 2010
Construction Start Date:	2010	2012
In-Service Date:	November 2011	November 2011
Total Cost:	$155 million	$9 million

[68] PAC/500, Teply/36, 45 (Naughton Units 1 and 2); PAC/500, Teply/54 (Dave Johnston Unit 4); PAC/500, Teply 75-76 (Wyodak); PAC/500, Teply/83 (Jim Bridger Unit 3).
[69] PAC/500, Teply/66.
[70] *See* PAC/500, Teply/28-39; PAC/2002/Teply. Permit MD-5156 is available as Sierra Club exhibit SC/105/Fisher. Please note that the Company has informed Sierra Club that exhibit SC/105 is non-confidential.
[71] *See* PAC/500, Teply/39-47; PAC/2002/Teply.

Dave Johnston Unit 4[72]	
	Dry Flue Gas Desulfurization and Baghouse System
Targeted Pollutant(s):	SO_2, PM
Date of Permit Issuance	June 2008 (Air Quality Permit MD-5098) December 2009 (BART Permit MD-6041)
Compliance Deadline	December 31, 2012
Date of Contract Execution	January 2008
Construction Start Date:	2008
In-Service Date:	April 2012
Total Cost:	$104 million

Hunter Unit 1[73]	
	Scrubber Project
Targeted Pollutant(s):	SO_2
Date of Permit Issuance	March 2008 (Utah Approval Order DAQE-AN0102370012-08)
Compliance Deadline	2014
Date of Contract Execution	December 2009
Construction Start Date:	2011
In-Service Date:	June 2012
Total Cost:	$52 million

Hunter Unit 2[74]		
	Scrubber Project	**Low NO_x Burner**
Targeted Pollutant(s):	SO_2	NO_x
Date of Permit Issuance	March 2008 (Utah Approval Order DAQE-AN0102370012-08)	
Compliance Deadline	2013	2013
Date of Contract Execution	December 2009	January 2010
Construction Start Date:	2010	2011
In-Service Date:	March 2012	May 2011
Total Cost:	$25 million	$5 million
	Baghouse Conversion	
Targeted Pollutant(s):	PM	
Date of Permit Issuance	March 2008 (Utah Approval Order DAQE-AN0102370012-08)	
Compliance Deadline	2013	
Date of Contract Execution	December 2009	
Construction Start Date:	2010	
In-Service Date:	May 2011	
Total Cost:	$50 million	

[72] *See* PAC/500, Teply/47-57; PAC/2005/Teply. The emissions control project at Dave Johnston Unit 4 was completed in conjunction with the Dave Johnston Unit 3 emissions control project that was placed in service in 2010 and found prudent in Docket UE 217 (the Company's 2010 general rate case).
[73] *See* PAC/500, Teply/57-69; PAC/2003/Teply.
[74] *Id.*

Wyodak[75]		
	Baghouse Project	**Low NO_x Burner**
Targeted Pollutant(s):	PM, SO_2	NO_x
Date of Permit Issuance	May 2009 (Air Quality Permit MD-7487) December 2009 (BART Permit MD-6043)	May 2009 (Air Quality Permit MD-7487) December 2009 (BART Permit MD-6043)
Compliance Deadline	December 31, 2011	December 31, 2011
Date of Contract Execution	May 2009	March 2010
Construction Start Date:	2010	2011
In-Service Date:	April 2011	April 2011
Total Cost:	$103 million	$11 million

Jim Bridger Unit 3[76]	
	Scrubber Project
Targeted Pollutant(s):	SO_2
Date of Permit Issuance	April 2007 (Air Quality Permit MD-1552) March 2009 (Air Quality Permit MD-1552A)
Compliance Deadline	2013
Date of Contract Execution	December 2008
Construction Start Date:	2010
In-Service Date:	June 2011
Total Cost:	$17 million

4. Installing the Emissions Control Equipment and Continuing to Operate the Units was the Least Cost, Adjusted for Risk, Option for Customers

Before making the final decision to move forward with installation of emissions control equipment at a specific unit and signing construction contract(s), the Company performed a PVRR(d) analysis. This analysis compared the expected costs of installing the emissions control equipment and continuing to operate the plant through the end of its depreciable life against replacing the output of the plant with market purchases. In determining the expected costs of continued operation, the Company included known and reasonably anticipated future capital investments in the plant, as well as assumptions regarding national economic conditions, natural gas prices, and future carbon risk. The

[75] *See* PAC/500, Teply/69-78; PAC/2006/Teply.
[76] *See* PAC/500, Teply/78-87; PAC/2004/Teply.

Company structured its PVRR(d) analysis to be an objective measure of the cost-effectiveness of installing emissions control equipment at the unit without favoring a particular outcome.

The PVRR(d) analyses were usually conducted approximately three to six months before the Company executing contracts for the installation of the environmental controls. Reevaluation of the economics of projects after the contracts were executed or before beginning construction of a project did not typically occur, because at that time there was no material reason to conduct such reevaluations. Though forward market prices had begun to decline beginning in early 2009, there was no established trend indicating that the decline would continue and result in the dramatically lower natural gas prices that we see today.[77]

For the emissions control investment(s) at each unit, the results of the PVRR(d) analysis showed that installing the equipment and continuing to operate the unit through the end of the unit's depreciable life was the least-cost option for customers, with demonstrated benefits ranging from moderate to significant. Certain parties argue that the PVRR(d) analyses were flawed; however, the Company demonstrated in reply and surrebuttal testimony that the parties' arguments were based on after-the-fact adjustments that used information that was not available at the time the decision to invest was made, used invalid economic assumptions,[78] or did not affect the results of the PVRR(d) analyses to the degree alleged by the parties.[79] Furthermore, the parties' arguments criticize the Company's *subjective* decision-making process, thereby failing to address the correct prudence standard. The parties' arguments do not provide any basis to conclude that the Company's emissions

[77] PAC/1500, Teply/12-13.
[78] For example, the parties' adjustments selectively update the analyses by using updated forward price curves, but do not update the analyses to reflect actual reductions in the costs of emissions control equipment. PAC/2000, Teply/11.
[79] PAC/1500, Teply/7-38; PAC/2000, Teply/9-23.

control investment decisions were *objectively* unreasonable based on available information at the time the decision was made.

The PVRR(d) analysis is intended to reflect numerically known and reasonably foreseeable changes to existing circumstances. These include assumptions regarding environmental regulations, market prices, and customer loads. Beyond the PVRR(d) analysis, the Company also assesses the realities and challenges of forecasting future policy decisions, rulemaking outcomes, and litigation results. This is necessarily a difficult task, in particular for projects that require multi-year implementation timelines.

Fuel, operation and maintenance costs, emissions costs, and other on-going capital revenue requirements costs were subtracted from the replacement power costs to derive a net change in projected revenue requirement. The cost of replacement power was assumed to be equal to the then-current Company official forward price curve. The most recent official forward price curve was used in each analysis. With the exception of the Hunter PVRR(d) analyses, replacement power costs were assumed to begin during the year that the analysis was conducted and to continue through the end of the remaining depreciable life of the relevant unit. For the Hunter units, replacement power costs were assumed to begin during the year that the emissions control equipment would become operational (2012). Market prices were chosen as the proxy cost of replacement power as a conservative assumption because at the time of the analyses a new replacement generation resource's all-in costs were generally significantly unfavorable in a deterministic PVRR(d) analysis when compared to forward market curves, making comparison to new replacement generation on a PVRR(d) basis even more unfavorable.

While the Company did not attempt to rebut all of the parties' proposed PVRR(d) changes in reply or surrebuttal testimony to avoid confusing the review of pertinent facts in the case, the Company did address certain arguments specifically. For example, assuming that replacement power costs begin in the year of the analysis is reasonable. In response to the Sierra Club's proposal to assume that replacement power costs could reasonably be adjusted to correspond to the applicable compliance deadline, however, the Company recalculated its PVRR(d) analyses using this assumption.[80] This recalculation did not change the overall results of the studies, and did not show that installing the equipment was uneconomic.[81]

The Company also made assumptions regarding the costs associated with continuing to run the relevant unit. Fuel pricing was estimated based on the then-current ten-year business plan, with the corporate escalation rate applied thereafter through the end of the depreciable life of the unit. The PVRR(d) analysis assumed that recovery of the capital costs of the environmental controls began in the year that the analysis was performed. In response to the Sierra Club's alternative approach (assuming recovery of the capital costs begins the year after the controls are installed and operational), the Company recalculated its PVRR(d) analyses using this assumption.[82] This recalculation similarly left the overall results of the studies unchanged, and it did not show that installing the equipment was uneconomic.[83]

5. Conclusion

The Company has provided substantial evidence that its decisions to invest in emissions control equipment at Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter

[80] PAC/1500, Teply/18, 21, 24-25, 32, 36.
[81] *Id.*
[82] PAC/2000, Teply/ 15-16.
[83] PAC/1500, Teply/18, 21, 24-25, 32, 36.

Units 1 and 2, Wyodak, and Jim Bridger Unit 3 were objectively reasonable given the information available at the time the decisions were made. The Company has also shown that these emissions control investments are required by legally enforceable state regulations and permits, are currently being used to serve customers, and are providing emissions reduction benefits. The Commission should therefore find that the Company's emissions control investments are prudent and used and useful to serve customers.

B. The Company's Proposed PCAM

PacifiCorp's proposed PCAM is a rate mechanism designed to allow the Company to collect or credit the difference between its prudent, actual NPC incurred to serve its Oregon customers and the amount of NPC collected from these customers through rates.[84] On a monthly basis, the Company proposes to compare its actual system net power costs (Actual NPC) to net power costs embedded in rates (Base NPC), and defer the Oregon-allocated differences in a balancing account.[85] The Company proposes to calculate a PCAM rate annually to collect from or credit to customers the accumulated balance over the subsequent year, subject to a prudence review.

The PCAM is designed to complement the Company's current Transition Adjustment Mechanism (TAM), with the TAM annually resetting the Base NPC subject to true-up in the PCAM.[86] The PCAM also builds on the Company's Renewable Adjustment Clause (RAC), with the RAC allowing recovery of the fixed costs of SB 838 compliance and the PCAM allowing recovery of the variable (*i.e.,* NPC-related) costs or benefits of SB 838 compliance.[87]

[84] PAC/900, Duvall/14.
[85] PAC/900, Duvall/14, 35-36.
[86] PAC/900, Duvall/15.
[87] PAC/900, Duvall/15.

The Company's dollar-for-dollar PCAM for prudent NPC is a solution to the challenges associated with accurately forecasting PacifiCorp's NPC in rates, especially with the addition of a new, large fleet of renewable resources.[88] Over the last five years, the Company has consistently and substantially under-recovered its NPC.[89] With increasing NPC volatility from renewable resources, the adoption of the Company's proposed PCAM is necessary to effectively address this issue. A dollar-for-dollar PCAM ensures that neither the Company nor its customers will be unfairly enriched or harmed by cost variances that are out of the Company's control. The PCAM will also benefit customers by minimizing controversies associated with NPC forecasts, reducing credit agency imputed debt, and allowing customers to receive the direct benefits of positive variances in forecast wind generation, market prices, or other NPC inputs.[90]

1. PacifiCorp's Proposed PCAM is Consistent with Applicable Legal Standards

In establishing fair and reasonable rates, ORS 756.040 requires the Commission to "balance the interests of the utility investor and the consumer[.]"[91] As part of this balancing of interests, the Commission "must allow a utility the opportunity to recover increased operating expenses that are prudently incurred."[92] This is the basic legal premise supporting PacifiCorp's proposed PCAM.

In addition, SB 838 includes a cost recovery provision (ORS 469A.120) that allows the Company to recover in rates "all prudently incurred costs associated with compliance"

[88] PAC/900, Duvall/15.
[89] PAC/900, Duvall/16.
[90] PAC/900, Duvall/29-30.
[91] ORS 756.040.
[92] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket UE 115, Order No. 01-988 at 5 (Nov. 20, 2001) (denying reconsideration of prior order that held that the Commission could consider the impact of a rate increase on customers but could not use rate shock as the basis for disallowing recovery of prudently incurred costs.).

with Oregon's RPS.[93] This specifically includes "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."[94] Neither SB 838 nor the Commission's rules define the terms "integrate, firm or shape" as used in SB 838; according to their ordinary usage, the terms refer to the actions the Company must take on a real-time basis to balance its system to address large amounts of new intermittent renewable resources.[95]

SB 838 (specifically ORS 469A.120(2)) requires the Commission to establish an automatic adjustment clause for the timely recovery of the prudent costs of acquiring or building renewable resources and associated transmission. Under this provision, the Commission established the RAC in Order No. 07-572, which allows the Company to recover the capital costs of the renewable energy source and associated transmission, forecasted operation and maintenance costs, forecasted property taxes, forecasted energy tax credits, and other forecasted costs and cost offsets authorized by SB 838 and not captured in the Company's annual power cost update.[96] ORS 469A.120(2) does not, however, specifically address the appropriate mechanism for recovery of the variable costs associated with SB 838 compliance. As discussed below, a PCAM that operates similarly to an automatic adjustment clause presents the only option for the Company to fully recover these variable costs, as authorized by ORS 469A.120(1).

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[93] ORS 469A.120(1).
[94] ORS 469A.120(1).
[95] PAC/900, Duvall/27.
[96] *See In the Matter of Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket UM 1330, Order No. 07-572 at 3 (Dec. 19, 2007).

In 2007, when the Company entered into a stipulation on the RAC, the intent was for the annual TAM filing would allow for timely recovery of the NPC impact of its renewable generation resources.[97] The Company's experience, however, has shown that a PCAM is necessary for the Company to recover its prudently incurred costs associated with complying with SB 838. The need for a PCAM is underscored by the fact that SB 838 increases the Company's renewable energy requirements to 25 percent of retail load by 2025.[98]

The Commission has not expressly addressed the standards for a post-SB 838 PCAM. The Commission's most recent opinion on PCAM design in a litigated case, Order No. 07-015, was decided before enactment of SB 838 in June 2007. In that decision, the Commission concluded that a PCAM should "be adopted to capture power cost variations that exceed those considered part of normal business risk."[99] The Commission set an asymmetric recovery deadband of 150/75 basis points as well as an earnings deadband of 100 basis points to capture "normal business risk" pre-SB 838. As discussed below, PacifiCorp has established that its "normal business risk" has increased by at least this deadband range as a result of SB 838.

The Commission has acknowledged the need to reevaluate the design of regulatory cost recovery mechanisms in the face of increased risk. Notably, in adopting the current Purchase Gas Adjustment (PGA) mechanisms in Order No. 08-504, the Commission found that "[c]hanges in gas markets have increased gas supply risks for shareholders," and "[t]hat increased risk should be recognized in modifications to the PGA mechanism."[100] In that

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[97] PAC/900, Duvall/28.
[98] PAC/900, Duvall/28.
[99] *In the Matter of Portland General Electric Company,* Dockets UE 180/UE 181/UE 184, Order No. 07-015 at 26 (Jan. 12, 2007).
[100] *In re Investigation into Purchase Gas Mechanisms*, Docket UM 1286, Order No. 08-504 at 18 (Oct. 21, 2008).

order, the Commission adopted a PGA with sharing bands for costs and earnings (either 90/10 or 80/20 at the utility's election), but without a deadband set on basis points, earnings, or dollars.[101] The Company's PCAM proposal similarly requests that the Commission find past PCAM designs inappropriate, recognizing that SB 838 has increased normal power supply risk for PacifiCorp.

2. PacifiCorp's Proposed PCAM is Designed Specifically for PacifiCorp

The Company proposes a PCAM under ORS 756.040, ORS 757.210(1), and ORS 469A.120(1) that is similar to the RAC. The PCAM would provide dollar-for-dollar recovery of the difference between Base NPC and Actual NPC. Although the PCAM does not include sharing bands, deadbands, or an earnings review, to recover costs under the PCAM the Company would be required to establish the prudence of its Actual NPC.

a. Description of PacifiCorp's Proposed PCAM

In PacifiCorp's PCAM proposal, the balancing account and PCAM rate serve as the true-up mechanism to recover or credit the monthly differences between Base NPC and Actual NPC. Any differences in the system per-unit cost will be multiplied by actual Oregon MWh load in that month and the product will be deferred in the balancing account.[102] The monthly under- or over-recovery will accumulate in the balancing account and earn interest at the Company's most recently approved weighted average cost of capital in Oregon. The Company will calculate a PCAM rate annually to collect from or credit to customers the accumulated balance over the subsequent year.[103]

The Company proposes to file annual PCAM reconciliations on May 15 each year, with a new PCAM rate effective date of January 1 of the following year. The Company

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[101] *Id*.; OAR 860-022-0070.
[102] PAC/900, Duvall/35-36.
[103] PAC/900, Duvall/36.

proposes to file its first PCAM application addressing a deferred amount in the balancing account on May 15, 2014, truing up 2013 Base NPC to 2013 Actual NPC.[104]

On an annual basis, the cumulative deferred balance in the balancing account will be recovered through proposed Schedule 206. The Company proposes the same rate spread for the PCAM as that used for Schedule 201 TAM rates in effect during the one-year PCAM accrual rate period.[105] The Company proposes to exempt direct access customers who did not pay cost-based NPC during the one-year PCAM accrual period from the PCAM adjustment for that year of service.[106]

The Company will calculate the PCAM using the same components of NPC used in the Company's TAM proceedings and modeled by the Company's GRID model.[107] The PCAM will not include any costs associated with fixed cost recovery (*i.e.*, capital investment in rate base). The Company will adjust Actual NPC as booked to remove prior period accounting entries and include applicable Commission-adopted adjustments reflected in the most recent TAM filing.[108] The Company will not adjust Actual NPC for wind generation, hydro conditions, or forced outages because these factors give rise to the fluctuations in NPC that this mechanism is designed to capture.

b. PacifiCorp's Proposed PCAM will Address the Company's Under-Recovery of NPC in Rates

A driving force behind PacifiCorp's PCAM proposal is the need to end the Company's significant under-recovery of NPC in Oregon rates. Since the TAM was adopted in 2007, the Company has under-recovered more than one-half billion dollars in system NPC

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[104] PAC/900, Duvall/36.
[105] PAC/1300, Griffith/17.
[106] PAC/1300, Griffith/17.
[107] PAC/900, Duvall/34.
[108] PAC/900, Duvall/35.

or approximately $134 million on an Oregon basis.[109] PacifiCorp's under-recovery of NPC in rates is a function of the challenges of forecasting NPC,[110] which relies on inherently volatile inputs such as market prices and generation output. Other factors that have contributed to PacifiCorp's NPC under-recovery include TAM settlements designed to minimize controversy and uncertainty around proposed NPC adjustments; normalized forecasts for hydro and wind generation; and TAM Guideline limitations on the scope and timing of updates to forecasted inputs that are stricter than the annual updates for other utilities.[111] While NPC forecasting challenges have always been present, the introduction of a new fleet of wind resources has exponentially increased the difficulty of forecasting PacifiCorp's NPC.[112]

The volatility of key NPC inputs (notably wind generation) results in a bias toward the under-forecast of NPC in rates.[113] The Commission has previously recognized the under-forecast bias associated with forecasting NPC in rates in rejecting adjustments designed to reduce overall NPC.[114]

c. PacifiCorp's Proposed PCAM Recognizes that its New Fleet of Renewable Generation has Increased the Complexity of PacifiCorp's System Operations and the Difficulty of Forecasting NPC

Since SB 838 was enacted in 2007, the Company has added 1,400 MW of new wind resources to its generation portfolio and certified 300 MW of hydro as low-impact hydro

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[109] *In the Matter of PacifiCorp, dba Pacific Power 2013 Transition Adjustment Mechanism,* Docket UE 245, Opening Brief at 10 (Sep. 14, 2012). *See also* PAC/900, Duvall/16; PAC/1800, Duvall/10, 12 (Table 4).
[110] *In the Matter of PacifiCorp, dba Pacific Power 2013 Transition Adjustment Mechanism*, Docket UE 245, Opening Brief at 11 (Sep. 14, 2012).
[111] *See, e.g., In the Matter of Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket UE 195, Order No. 08-238 at Appendix A, Section 11 (Apr. 28, 2008) (allowing updates for hydro generation on a non-normalized basis); *In the Matter of Portland General Electric Company 2013 Annual Power Cost Update*, Docket UE 250, PGE/100, Niman-Peschka-Hager/1, line 21 (March 30, 2012) (loads updated in rebuttal update).
[112] PAC/1700, Bird/8-10.
[113] *In the Matter of PacifiCorp, dba Pacific Power 2013 Transition Adjustment Mechanism*, Docket UE 245, Opening Brief at 10 (Sep. 14, 2012).
[114] Order No. 07-015 at 12.

under SB 838.[115] The Company now integrates approximately 2,375 MW of wind generation, with Company-owned wind generation comprising approximately 10 percent of the Company's total installed generation capacity.[116] Unlike thermal generation, wind generation fluctuates widely. In 2011, the production from the Company's total portfolio of owned and contracted wind generation fluctuated hourly from zero to 27.4 percent of the Company's total system retail loads throughout the year, and from zero to over 90 percent of the Company's total wind capacity.[117]

The addition of this large fleet of intermittent resources has increased the risk and complexity of PacifiCorp's system operation and decreased the Company's ability to accurately forecast NPC. The Federal Energy Regulatory Commission (FERC) recently recognized the major changes in power delivery systems caused by variable energy resources (VERs) such as wind:

> VERs are making up an increasing percentage of new generating capacity being brought on-line. This evolution in the Nation's generation fleet has caused the industry to reevaluate practices developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation.[118]

Intermittent resources have no predictable pattern of delivery. They start and stop quickly, and must be firmed, shaped, and integrated by the Company's dispatchable resources on a moment-to-moment basis.[119] Other NPC inputs—such as load, hydroelectric generation, and thermal generation—are unpredictable, but they are not intermittent. As a balancing authority, the Company is obligated to balance load and resources within every

[115] PAC/1700, Bird/2-3.
[116] PAC/1700, Bird/3, lines 19-22.
[117] PAC/1700, Bird/4, lines 3-10.
[118] FERC Order No. 764 at 3, Docket No. RM 10-11-000 (June 22, 2012).
[119] PAC/900, Duvall/17.

hour to maintain reliable service to customers.[120] The fluctuating nature of renewable resources like wind requires the Company to set aside additional balancing reserves in every hour to ensure adequate capacity.[121]

The increase in renewable generation resources also affects market prices and further complicates forecasting NPC.[122] The Company's wind resources are concentrated in high wind resource areas and weather changes in these areas result in dramatic swings in wind generation output—from zero to full nameplate capacity—and with the increase in incremental supply, there is a corresponding decrease in market prices.[123] As the amount of intermittent renewable resources increases, so does the impact on market prices. The increase in intermittent renewable generation resources has also resulted in a shift in the Company's resource portfolio to a less predictable generation profile due to increased reliance on flexible natural gas generation to back up intermittent renewable generation.[124]

While it is impossible to isolate and quantify the full NPC impacts associated with the Company's new fleet of renewable resources, the Company has demonstrated the magnitude of costs associated with just the variances between forecast and actual wind generation levels. Measuring the change in the net market value of its owned wind generation from 2007 to 2011, using actual and forecast wind generation levels and actual and forecast market prices, the impact ranged from $4.2 million to $66.4 million of over-forecast value on a total Company basis, or a five-year average of $35.1 million.[125] Grossing up the wind generation to PacifiCorp's 2013 wind resources included in the 2013 TAM increased the range of

[120] PAC/1700, Bird/4, lines 25-26.
[121] PAC/1700, Bird/4-5.
[122] PAC/1700, Bird/5, lines 5-15.
[123] PAC/1700, Bird/5, lines 7-15.
[124] PAC/1700, Bird/8, lines 20-23.
[125] PAC/1800, Duvall/5.

variances to between $24.0 million to $101.8 million over-forecast value on a total Company basis, or a five-year average variance of $55.9 million.[126] Grossing up the wind generation for the 2025 wind penetration levels required by SB 838 increased the range of variances from $59.4 million to $297.7 million over-forecast total system, for a five-year average of $160.9 million.[127]

The Company's wind variance cost analysis is important for two reasons. First, it demonstrates that the Company's current and forecast wind generation variance risk alone is large enough to fully offset the deadbands set in Order No. 07-015 to capture normal business risks.[128] Starting with the deadbands correlated for the normal business risks that existed pre-SB 838 and adjusting for new wind variance risks assigned to customers under SB 838 requires adoption of a PCAM without deadbands. Any other approach will directly or indirectly result in PacifiCorp continuing to absorb SB 838 compliance costs, contrary to Oregon law.

Second, the variance analysis shows that the NPC impacts of SB 838 compliance are not covered by the Company's wind integration charges in rates.[129] Forecast NPC cannot capture the minute-to-minute variations in wind generation and the resulting impacts on the rest of PacifiCorp's system. In actual operations, the reserves needed vary based on wind output, and the cost of holding reserves varies with market prices and the availability of reserve carrying resources in the Company's fleet.[130] The full impact of variations in wind generation is not included in the Company's normalized NPC. The only way to capture

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[126] PAC/1800, Duvall/5.
[127] PAC/1800, Duvall/5-6.
[128] PAC/1800, Duvall/7.
[129] PAC/2200, Duvall/15-16.
[130] PAC/2200, Duvall/16.

these costs and permit their full recovery as required by SB 838 is through a dollar-for-dollar PCAM, subject to a prudence review.

d. PacifiCorp's Proposed PCAM is Consistent with its California Mechanism and the Vast Majority of Utility PCAMs

The Company currently has a dollar-for-dollar Energy Cost Adjustment Clause (ECAC) in California like the PCAM it is proposing in Oregon.[131] California is the only state in PacifiCorp's service territory that has both an RPS and a PCAM.[132] While PacifiCorp's other PCAMs have sharing bands, none have deadbands. In addition, the vast majority of PCAMs for utilities in PacifiCorp's cost of capital peer group do not contain deadbands, sharing mechanisms, or earnings reviews.[133] In fact, only seven out of 55 had a deadband and only four out of 55 had both a deadband and sharing bands.[134] Most telling is that only one out of 55 mechanisms contained a deadband, sharing bands, *and* an earnings review (PGE).[135] In support of its PCAM proposal in Docket UE 215, PGE also found that three percent of the utilities in its cost of capital peer group had a PCAM with a deadband only and six percent had a deadband with some kind of sharing mechanism.[136] In summary, the dollar-for-dollar PCAM PacifiCorp has proposed is consistent with the PCAMs now in place in a majority of jurisdictions.

[131] PAC/2200, Duvall/9, lines 11-15.
[132] Washington also has an RPS requirement but has adopted a unique cost allocation methodology that it applies to PacifiCorp's system-wide costs, including NPC, and to date that allocation method has precluded the use of a PCAM to true up actual NPC.
[133] PAC/900, Duvall/32; PAC/901/Duvall.
[134] PAC/2200, Duvall/10.
[135] Idaho Power's Oregon PCAM also includes these three elements, but the comparison chart includes Idaho Power's PCAM structure in Idaho because that is its primary service territory.
[136] PAC/2200, Duvall/10.

3. Staff and Intervenors Have Not Established a Basis for Rejecting PacifiCorp's Proposed PCAM

Staff, CUB, ICNU, and Kroger oppose PacifiCorp's proposed PCAM. Staff and CUB propose that the Commission adopt the same PCAM structure for PacifiCorp as the PCAM authorized for PGE in Order No. 07-015. Staff also points to Idaho Power's PCAM as another potential model. ICNU strongly opposes adoption of a PCAM for PacifiCorp, but if a PCAM is adopted, ICNU proposes using the structure from Order No. 07-015 with expanded sharing bands of 75/25 percent instead of 90/10 percent. ICNU also argues that if a PCAM is adopted, the Company's TAM should be eliminated. Kroger recommends a PCAM similar to the Company's PCAMs in Wyoming and Utah, which require a 70/30 percent sharing of variances, but have no deadbands or earnings test.

a. PGE's 2007 PCAM Design has been Superseded and is Inappropriate for PacifiCorp

There are several reasons why the Commission should reject the parties' proposal for a PCAM modeled after the 2007 PGE PCAM. First, it is undisputed that the 2007 PGE PCAM would have provided PacifiCorp zero percent recovery of its unrecovered NPC over the last five years.[137] In every year since 2007, the proposed 150/75 basis point deadband would have been too large to be exceeded, even though PacifiCorp's unrecovered NPC was more than $25 million in four of the five years.[138] Any proposed earnings deadband or sharing bands would have been rendered irrelevant by the large initial deadband.[139]

The applicable basis point deadband for 2011 would have been $43.2 million. PacifiCorp's Oregon NPC in rates in 2011 were approximately $322 million. Consequently, the deadband would require PacifiCorp to absorb over 13 percent of its total NPC before it

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[137] PAC/2200, Duvall/3.
[138] PAC/2200, Duvall/4, lines 3-5.
[139] PAC/2200, Duvall/4, lines 5-7.

could recover any unrecovered NPC.[140] To put this in perspective, PacifiCorp's 2013 proposed TAM increase is $3.4 million, approximately one percent of total NPC.[141] This demonstrates that, as applied to PacifiCorp, adoption of the 2007 PGE PCAM would be the equivalent of an outright rejection of PacifiCorp's request for a PCAM.

Second, because the deadband in the 2007 PGE PCAM is set through a basis points calculation, the deadband increases as the Company's rate base expands. For PacifiCorp, the deadband would have increased from $29.7 million/$14.8 million in 2007 to $43.2 million/$21.6 million in 2011.[142] The deadband is asymmetrical and the dollar value of the asymmetry expands as the deadband increases. These increases occurred because the Company's ratebase grew from 2007 to 2011, due in part to investments in new wind generation of $1.6 billion (total company) during this period.[143] Ironically, investment in new wind generation reduces NPC and increases rate base, meaning that a deadband mechanism tied to basis points would increase the deadband as a percentage of overall NPC for all new wind generation. It is contrary to the cost-recovery policy of SB 838 to set a cost-recovery deadband that expands in absolute dollars and as a percentage of total NPC based upon incremental investment in renewable generation.

Third, in Order No. 10-478 in Docket UE 215, the Commission adopted a stipulation that redesigned the 2007 PGE PCAM, adding a new $30 million/$15 million dollar-defined deadband in the place of the 150/75 basis point deadband.[144] PGE testified in that case that the financial community uniformly viewed the wide and asymmetrical deadband in the 2007 PGE PCAM as problematic. PGE also testified that the 2007 PGE PCAM design had not

[140] PAC/2200, Duvall/4.
[141] PAC/2200, Duvall/4.
[142] PAC/1800, Duvall/13.
[143] PAC/1800, Duvall/13.
[144] *In re Portland General Electric Company*, Docket UE 215, Order No. 10-478 at 10 (Dec. 17, 2010).

worked well, because it was complex and produced rate volatility.[145] In advocating for adoption of the 2007 PGE PCAM model in this case, Staff and intervenors ignore the revisions to the 2007 PGE PCAM adopted in Order No. 10-478 and the evidence in that case that the 2007 PGE PCAM had significant design problems.

Fourth, in Order No. 07-015 adopting the 2007 PGE PCAM, the Commission stated that the PCAM was "narrowly tailored to suit PGE."[146] Similarly, Order No. 10-478 indicates that the order should not be considered precedent for future dockets addressing PCAM policy issues.[147] Given this language—and the fact that neither PGE PCAM order addressed the impact of SB 838 compliance—the Commission should reject application of both the 2007 and 2010 PGE PCAM models to PacifiCorp.

In addition, application of a PCAM designed specifically for PGE is inappropriate given the operational differences between PGE and PacifiCorp. Unlike PGE, the Company is often a net seller in the wholesale markets and a decline in market prices actually increases the Company's NPC; the exact opposite is true for PGE.[148] PGE has over-forecast NPC in recent years, in contrast to the Company, which has under-forecast NPC.[149] Given these important distinctions, the same PCAM design could operate fairly for one company and unfairly for the other.

Fifth, as discussed above, the 2007 PGE PCAM does not reflect the additional business risk created by SB 838. By requiring acquisition of renewable generating resources, SB 838 fundamentally altered how utilities operate their generation systems, introducing

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[145] *In re Portland General Electric Company*, Docket UE 215, Direct Testimony of Hager-Valach (PGE/1100); Direct Testimony of Fetter (PGE/1300); Reply Testimony of Pope (PGE/1700); Reply Testimony of Fetter (PGE/1800).
[146] Order No. 07-015 at 27.
[147] *In re Portland General Electric Company*, Docket UE 215, Order No. 10-478 at 10, n.15 (2010).
[148] PAC/2200, Duvall/12, lines 4-6.
[149] PAC/2200, Duvall/8, lines 5-6.

volatility that cannot be modeled and changing the concept of "normal business risk" in the NPC context. In recognition of the additional volatility, and thus risk, associated with the RPS, the legislature explicitly shifted the costs of prudently incurred compliance costs to customers. Adoption of the 2007 PGE PCAM would effectively assign all of SB 838's NPC compliance costs in excess of those modeled in rates to PacifiCorp, contrary to SB 838's mandate.

b. Idaho Power's PCAM is Designed for Idaho Power's Operations and is Inappropriate for PacifiCorp

Staff also points to the Idaho Power PCAM as precedent for a PCAM with a large and asymmetric deadband and sharing bands. But Idaho Power is not subject to SB 838, and its PCAM does not address the SB 838 compliance cost issues that are at the heart of PacifiCorp's PCAM proposal.

In addition, Idaho Power's PCAM and annual NPC update were expressly designed to address Idaho Power's heavy reliance on hydro power. Idaho Power is allowed to reflect the latest forecast from the Northwest River Forecast Center for its hydro forecast just two months before the rate effective date rather than using a normalized hydro forecast.[150] This approach permits Idaho Power to more closely match forecast and actual hydro generation outside of the PCAM, which is a significant benefit because Idaho Power meets approximately half of its load with hydro. In contrast, PacifiCorp's TAM filings rely upon normalized hydro generation to determine forecast NPC. Staff's testimony unreasonably represents that the mechanism designed specifically around Idaho Power's resource portfolio and unique NPC forecasts is an appropriate benchmark for a PacifiCorp PCAM without addressing this material difference in hydro modeling.

[150] *In re Idaho Power Company*, Docket UE 195, Order No. 08-238 at Appendix A, Section 11 (2008).

c. Sharing Bands Do Not Create an Incentive to Manage NPC

Staff, CUB, ICNU, and Kroger all propose PCAMs that include sharing bands. The primary argument used to support sharing bands is that sharing creates an incentive for the Company to manage its NPC. Kroger proposes a 70/30 percent sharing on all amounts, with no deadband or earnings test. Staff and CUB propose a 90/10 percent sharing, and ICNU proposes a 75/25 percent sharing. Staff's, CUB's, and ICNU's sharing bands are all applied after the deadband, which makes them in all likelihood irrelevant.

The parties generally assert that, without sharing, PacifiCorp's proposed PCAM provides no incentive for PacifiCorp to manage its NPC. But the most powerful management incentive at the Commission's disposal is a prudence review, which is part of the structure of the Company's PCAM proposal. Nearly all NPC components are out of the control of the Company, including the level and variations in customer loads, wholesale power prices, natural gas prices, hydro generation, wind generation, and the timing of forced outages.[151] No artificially imposed incentive will enable the Company to control these factors.[152] Further, sharing bands do not create an incentive for the Company to act "more" prudently because the sharing cannot be avoided no matter how prudently the Company acts.

The Company must prudently dispatch its system to serve customers at the lowest cost regardless of whether there is an approved PCAM in place and regardless of whether that PCAM includes a sharing mechanism. Rather than functioning as an incentive, a sharing band functions as a predetermined disallowance of costs without a finding of imprudence. An ever-increasing share of PacifiCorp's NPC is tied to renewable resources and SB 838

[151] PAC/2200, Duvall/19.
[152] PAC/2200, Duvall/19.

compliance, and an automatic disallowance of a portion of NPC is contrary to that law and basic regulatory principles.

Furthermore, although the Commission has previously adopted sharing bands in PGE's and Idaho Power's PCAMs, the Commission has also recognized that sharing bands are not always appropriate. In Order No. 05-1261, the Commission recognized that sharing bands do not create an incentive to control uncontrollable costs, explaining that "since hydro availability is beyond the company's control, we are doubtful that sharing or any other design of a hydro-related PCA can provide much of a management incentive."[153]

d. Adoption of a PCAM Should Not Result in Elimination of the TAM because the Two Mechanisms Serve Different Purposes

ICNU argues that the Company's annual TAM filings render the Company's PCAM proposal "not only unnecessary but unbalanced for consumers."[154] In this case and in Docket UE 245, CUB has joined ICNU's argument that the Commission should eliminate the TAM. PacifiCorp's pre- and post-hearing briefs in Docket UE 245 address the TAM generally, including its history, purpose, and necessity, and summarize why the TAM has become an essential part of PacifiCorp's regulatory framework in Oregon.

From a practical perspective, the PCAM does not render the TAM unnecessary. The TAM and PCAM serve different purposes—the TAM updates forecast NPC and the PCAM trues up the forecast to actual NPC. Under ICNU's proposal, the forecast NPC in customer rates would become stale, and known changes in actual NPC levels would not be reflected in

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[153] *In the Matter of Portland General Electric*, Dockets UE 165/UM 1187, Order No. 05-1261 at 9 (Dec. 21, 2005).
[154] ICNU/111, Deen/9.

rates. Application of deadbands and sharing bands would further exacerbate the problem, resulting in automatic disallowance of prudent NPC or recovery of more than actual NPC.[155]

In Order No. 07-015, the Commission rejected similar arguments from ICNU. The Commission found that PGE's PCAM and PGE's annual update were mechanisms that "serve different purposes," and that it was "important to update the forecast of power costs included in rates to account for new information."[156] The Commission also found that "if the forecast is not updated each year, then PGE will be exposed to more than normal business risk."[157]

In reality, a PCAM makes annual TAM filings even more important to set the forecast NPC as accurately as possible and minimize variances that must flow through the adjustment mechanism after the fact. This forecast and true up structure is already in place for PGE and Idaho Power. The RAC is also tied to the annual NPC filings of PacifiCorp and PGE, meaning that changes to the TAM will have a cascading impact on the RAC and collectively move the regulatory process backward.[158]

In addition, the annual TAM filing is necessary to establish accurate transition adjustments for direct access customers and is required under statute.[159] In Dockets UM 1081 and UE 170, the Commission adopted a TAM with an annual NPC update to prevent cost-shifting from direct access to other customers. ICNU's proposal to eliminate the annual NPC update contravenes this policy because using outdated pricing information to calculate the transition adjustment could drive large swings in demand for direct access.

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[155] PAC/2200, Duvall/21.
[156] Order No. 07-015 at 18.
[157] *Id.*
[158] PAC/2200, Duvall/22.
[159] PAC/1800, Duvall/22.

Finally, the annual TAM has allowed PacifiCorp to avoid filing annual general rate cases in Oregon, which it has not been able to do in its other major jurisdictions.

4. Conclusion

The Company proposed a PCAM in this case to address its chronic under-recovery of prudently incurred NPC. The PCAM is designed specifically for PacifiCorp's operations, and recognizes the necessity of a dollar-for-dollar PCAM to recover the variable, prudent costs of compliance with SB 838 that are not captured through the RAC or the TAM. In addition, consistent with fundamental regulatory principles and ORS 756.040, the Company's proposed PCAM is designed to ensure that a utility customer's rates reflect the cost to serve that customer and send appropriate price signals to all customers. If NPC are reasonable and prudent, there is no basis for structuring a PCAM to automatically disallow these costs. There is also no basis to design a PCAM that arbitrarily withholds rate credits from customers when NPC are lower than forecast in rates. For these reasons, the Commission should adopt PacifiCorp's proposed PCAM.

C. The Mona-to-Oquirrh Transmission Project

To mitigate the rate impacts on customers and to minimize controversy in this case, the Company limited revenue requirement to plant in service through December 31, 2012, rather than through the end of the test period (December 31, 2013).[160] The one exception is the Mona-to-Oquirrh transmission project, which is the largest capital investment that will be placed in service during the test period.[161] To appropriately match recovery of the costs of this project with the benefits that the project will provide to customers, the Company proposes to recover its investment in the Mona-to-Oquirrh transmission project through a

[160] PAC/100, Reiten/8.
[161] PAC/1600, Dalley/2.

separate tariff rider that will become effective once the project goes into service during 2013.[162] This is consistent with the treatment of the Mona-to-Oquirrh transmission project in the forecast of NPC in the Company's 2013 TAM filing. The project is included in the GRID topology beginning in May 2013.

In addition to ensuring the appropriate matching of costs and benefits, the Company's proposal is consistent with the used and useful standard because the project's costs will not be included in rates until the project is in service and being used to serve customers.[163] The Company's proposal ensures timely recovery of an investment in a transmission line that is necessary to continue to provide safe, reliable, and adequate service to its customers.

1. Description of the Mona-to-Oquirrh Transmission Project

The Mona-to-Oquirrh transmission project consists of a single-circuit 500 kV transmission line originating from the Clover substation (being constructed near Mona, Utah), extending north about 70 miles to the future Limber substation (to be located in Tooele County, Utah), and continuing as a double-circuit 345 kV line for approximately 30 miles to the existing Oquirrh substation in South Jordan, Utah.[164] Construction began on the project in March 2011, and the project is expected to be placed in service in May 2013, which is during the test period in this case.[165] The Oregon-allocated revenue requirement associated with this project is approximately $12.6 million.[166]

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[162] PAC/1100, Dalley/14; PAC/1300, Griffith/15-16; PAC/1304, Griffith/1-3 (illustrative tariff at page 3).
[163] PAC/1600, Dalley/5.
[164] PAC/700, Gerrard/4-5.
[165] PAC/700, Gerrard/5-6.
[166] PAC/1601, Dalley/1-5. In this exhibit, PacifiCorp recalculated the Oregon-allocated revenue requirement for the Mona-to-Oquirrh transmission project using the stipulated weighted average cost of capital. In the Company's initial filing, the Oregon-allocated revenue requirement for the project was $13.1 million. PAC/1106, Dalley/1-6.

2. Need for and Benefits of the Mona-to-Oquirrh Transmission Project

The Mona-to-Oquirrh transmission project is necessary to maintain the Company's compliance with mandated North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability and performance standards. The project will strengthen the overall reliability of PacifiCorp's existing transmission system, mitigating the risk of customer outages and load curtailments. Given existing limited capacity on the system, the project is also necessary to support short- and long-term energy demands.[167] In addition, the Mona-to-Oquirrh transmission project will allow the Company to continue to meet native load service obligations in all of its states and continue to meet contractual obligations to third parties under its OATT.[168]

The Company's integrated resource plans for 2007, 2008, and 2011 evaluated the Mona-to-Oquirrh transmission project for cost-effectiveness from an integrated system perspective and included the Mona-to-Oquirrh transmission project as part of the Company's preferred resource portfolio.[169] These plans require reliable transport of designated network resources to meet network loads and adequate long-term transmission system capacity. The Mona-to-Oquirrh transmission project is essential to meeting these requirements.[170] Furthermore, the Company's economic analyses show significant benefits for all customers.[171] For example, a 2010 analysis showed that completion of the Mona-to-Oquirrh

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[167] The benefits of and the need for the Mona-to-Oquirrh project are discussed extensively in the Direct Testimony of Darrell T. Gerrard (Exhibit PAC/700). Specifically, see PAC/700, Gerrard/2, 9-14, 16-21. *See also In the Matter of PacifiCorp 2011 Integrated Resource Plan*, Docket No. LC 52, Staff's Final Comments and Recommendations at 41-42 (October 13, 2011) (recognizing the necessity and benefits of the project and recommending acknowledgement).
[168] PAC/700, Gerrard/13.
[169] PAC/700, Gerrard/18.
[170] PAC/700, Gerrard/9-10.
[171] PAC/700, Gerrard/12.

transmission project could result in a range of expected variable production cost savings from $331 million to $549 million.[172]

3. Applicable Legal Standards

a. The Prudence Standard

To be recoverable in customer rates, the Company's decision to build the Mona-to-Oquirrh transmission project, as well as the costs incurred in building the project, must be prudent. In this case, prudence is not a disputed issue before the Commission at this time for two reasons. First, the Stipulating Parties do not contest the prudence of the Company's decision to build the Mona-to-Oquirrh transmission project, nor does any other party.[173] Second, if the Company's proposal for a separate tariff rider is approved, the Stipulating Parties agree that the final costs of the line will be audited and reviewed for prudence before being included in rates.[174]

b. The Used and Useful Standard

As discussed above, the used and useful standard requires that utility property be "presently used" for providing utility service to be included in customer rates.[175] In this case, the Company proposes to recover its investment in the Mona-to-Oquirrh transmission project through a separate tariff rider beginning in 2013, when the project is placed in service. The project will therefore be "presently used for providing utility service to the customers" at the time the investment in the project is included in customer rates.

[172] PAC/700, Gerrard/11.
[173] Partial Stipulation at ¶ 14(c).
[174] *Id.*
[175] ORS § 757.355(1).

4. PacifiCorp's Proposal Ensures that the Mona-to-Oquirrh Transmission Project is Used and Useful to Serve Customers at the Time it is Included in Customer Rates

The used and useful standard requires that utility property be "presently used" for providing utility service to be included in customer rates. Although the Company's proposal ensures that the Mona-to-Oquirrh transmission project will not be included in rates until after the project is being used to serve customers, Staff, CUB, and ICNU nonetheless argue that the Company's proposal to recover the cost of the investment through a separate tariff rider is inconsistent with the used and useful standard. Staff states that the "Company should be held to the intent of the used and useful standard."[176] ICNU argues that utility investments "should be completed before the test year in question to be included in rates."[177] CUB states that it "concurs with Staff and ICNU that the project should not be included in rates before it comes online and is used and useful."[178] It is noteworthy that none of these parties have proposed to remove the Mona-to-Oquirrh transmission project from the GRID topology in the Company's TAM filing.

The parties' arguments regarding the used and useful standard are unpersuasive. First, under the Company's proposal, recovery of its investment in the Mona-to-Oquirrh transmission project will not begin until the project is placed in service. The transmission line will therefore be "presently used for providing utility service to the customer"[179] at the time the Company's investment is included in customer rates. The Company's proposal is consistent with both the intent and the substance of ORS 757.355(1). The Company's

[176] Staff/1000, Johnson/2-3.
[177] ICNU/111, Deen/2-4.
[178] CUB/200, Jenks-Feighner/45.
[179] ORS § 757.355(1).

proposal is also consistent with CUB's statement that the project not be included in rates "before it comes online and is used and useful."

Second, the Company's proposal was specifically designed to address the parties' concerns about the used and useful standard. The inclusion of capital additions forecast to be completed during the future test period has been a significant source of controversy in previous cases, including Docket UE 210 (the Company's 2009 general rate case). In the Company's two most recent general rate cases (Docket UE 217 and this case), the Company included plant additions projected to be placed in service before the beginning of rate effective period[180] to minimize controversy and mitigate rate impacts for customers. But in this case the single largest capital investment forecast to be placed into service after the rate effective date (but during the test period in this case) is the Mona-to-Oquirrh transmission project. To begin recovering the investment concurrent with the provision of service to customers, while also ensuring that the transmission project is unquestionably used and useful before recovery begins in customer rates, the Company proposed the separate tariff rider.

Third, Staff and CUB focus on the wrong period in asserting that the Mona-to-Oquirrh transmission project is not used and useful. Staff and CUB argue that the project will not be used and useful before the rates in this case go into effect on January 1, 2013, and therefore the Commission should reject the Company's proposal. But this argument is irrelevant because the Company is not proposing to include the Mona-to-Oquirrh transmission project in rates on January 1, 2013. Under PacifiCorp's proposal, the project

[180] The Company's test year is calendar year 2013, which corresponds to the rate effective period (beginning January 1, 2013).

will not be included in rates until *after* the project goes into service in 2013.[181] While it is true that the project will not be in service before January 1, 2013, the project will be in service before being added to customer rates, and therefore the Company's proposal meets the used and useful standard.[182]

5. The Company's Proposal is Consistent with Commission Precedent

Despite the parties' assertions to the contrary, the Company is not seeking "special ratemaking treatment"[183] for the Mona-to-Oquirrh transmission project, but rather is seeking to include in customer rates a capital project that will be used and useful during the test year. Rather than being "special," the Company's approach is consistent with general ratemaking principles in jurisdictions using future test periods.[184] The Company's proposal is also consistent with Commission precedent.

In Docket UE 248, Idaho Power Company filed a request for a rate revision to include its Langley Gulch gas-fueled generating plant in customer rates. The inclusion of Langley Gulch results in a 7.32 percent rate increase for Idaho Power's Oregon customers.[185] Because new rates from Idaho Power's 2011 general rate case had become effective on March 1, 2012, approximately one week before the filing initiating UE 248, Idaho Power argued that the proposed ratemaking was appropriate: "Given that the Commission just completed an evaluation of the Company's costs and revenues, administrative efficiency militates in favor of evaluating the inclusion of Langley in rates in this case rather than in

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[181] PAC/1600, Dalley/7.
[182] *See* ORS § 757.355(1).
[183] *See* ICNU/100, Deen/24; ICNU/111, Deen/3.
[184] PAC/1600, Dalley/4.
[185] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service Due to the Inclusion of the Langley Gulch Power Plant Investment in Rate Base*, Docket No. UE 248, Order No. 12-358 at 1 (Sept. 20, 2012).

another general rate case."[186] CUB and NIPPC participated in the proceeding and reached a settlement with Idaho Power. The Commission approved the settlement, allowing Langley Gulch to be included in rates on October 1, 2012, seven months after the beginning of the test period used in the general rate case.[187] CUB did not file testimony in the docket, but there is no indication in the Commission order, the stipulation, or the joint explanatory brief in support of the stipulation that CUB raised concerns about this ratemaking approach.

The Company's proposal is also consistent with the Commission's decision regarding PGE's Port Westward natural gas plant.[188] In that case, PGE proposed that the Commission "approve both the fixed and variable revenue requirements associated with Port Westward"[189] as part of its general rate case, even though the plant would not be in service until three months after the requested rate effective date. Staff stated that it did not necessarily oppose this approach to recovery. CUB argued that the five-month gap between when new rates would be effective and the in-service date for Port Westward was the result of a timing problem created by PGE. CUB also raised concerns about what would happen if the in-service date were delayed. The Commission found that CUB's concerns about a delay in the in-service date were valid.[190] To address these concerns, the Commission adopted a three-step process with varying levels of additional review depending on the operational date of the facility. If Port Westward became operational within 60 days of the estimated online

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[186] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service Due to the Inclusion of the Langley Gulch Power Plant Investment in Rate Base*, Docket No. UE 248, Idaho Power Company's Executive Summary at 4 (March 9, 2012).
[187] Order No. 12-358 at 4.
[188] *In the Matter of Portland Gen. Elec. Co.*, Docket Nos. UE 180/UE 184, Order No. 07-015 at 50 (Jan. 12, 2007). *See also In the Matter of Portland Gen. Elec. Co.*, Docket No. UE 93, Order No. 95-1216 at 7-8(Nov. 20, 1995)(allowing fixed costs of the Coyote Springs gas-fueled generating plant into rates based on previous "recent, thoroughly contested rate case which provides a comprehensive analysis of all elements relating to PGE's costs and revenues[.]").
[189] In the Matter of Portland Gen. Elec. Co., Docket No. UE 180, Direct Testimony of Piro-Lesh (PGE/100).
[190] *Id*. at 50.

date of March 1, 2007, no additional review would be necessary. If it became operational on or after April 30, but before September 1, 2007, Staff and intervenors would have 15 days from the online date to determine whether new information required re-examination of PGE's costs and revenues. If it became operational after September 1, 2007—eight and a half months after rates in UE 180 went into effect—PGE was required to file a new rate case.[191]

The Commission has allowed similar rate treatment in other cases as well. In Docket UG 181, Avista requested a rate increase that included its East Medford pipeline and Jackson Prairie storage facility capital projects. The Commission approved a stipulation adopting a two-stage rate increase.[192] The first stage rates went into effect on April 1, 2008. The second stage went into effect on November 1, 2008, after Avista's East Medford pipeline and Jackson Prairie projects went into service and were used and useful. In Docket UE 215, PGE requested inclusion of four controversial capital projects in rates: the Coyote Springs upgrade, pollution controls at its Boardman plant, cyber security investments, and "2020 Vision." CUB objected to including these projects in rates, arguing that they would not be used and useful by the requested rate effective date of January 1, 2011, and recovery was just a question of regulatory lag. PGE, CUB, Staff, ICNU, and Kroger reached a settlement on this issue. PGE agreed to remove the four projects, but the other parties agreed to support deferred accounting treatment for the capital costs of the projects (beginning on the in-service date and continuing through the effective date of new rates in PGE's next rate case) and agreed to support amortization of the deferral.

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[191] *Id*.
[192] *In the Matter of Avista Corp*, Docket UG 181, Order No. 08-185 at 2 (Mar. 31, 2008).

Finally, in Docket UE 217, the Company sought recovery of its investment in the Populus-to-Terminal transmission line, which was not complete before parties settled and agreed to inclusion of the line in rates. The stipulation included a provision (similar to what the Company is requesting here) that allowed recovery of the Company's investment in the line through a separate rate schedule if the in-service date were delayed until after the beginning of the rate effective period.[193]

6. PacifiCorp's Proposal Properly Matches the Benefits Received and the Costs Borne by Customers

Staff and CUB argue that the Mona-to-Oquirrh transmission project will not be complete until mid-2013, and is therefore an event that occurs "between rate cases" that "should be excluded from rate base under the principle of regulatory lag."[194] CUB and ICNU similarly argue that the recovery of the Company's investment in the Mona-to-Oquirrh transmission project is simply a matter of regulatory lag.[195]

"Regulatory lag" is a term used to describe "the time interval between the occurrence of a cost or revenue and the recognition of the same cost or revenue in rates.[196] Regulatory lag is a consequence of traditional rate regulation (absent fully forecast test periods); it is not a governing principle or rate regulation. In fact, regulatory lag should be avoided to properly match the timing of the recovery of the costs of providing service with the customers' receipt of the benefits of that service.[197] By beginning recovery of the Company's investment in the Mona-to-Oquirrh transmission project concurrently with the project's provision of service to customers, the Company's proposal appropriately matches the timing of recovery of the costs

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[193] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 217, Order No. 10-473, Appendix A, ¶ 10(a) (Dec. 14, 2010).
[194] Staff/1000, Johnson/3.
[195] ICNU/100, Deen/24; CUB/200, Jenks-Feighner/45, 47.
[196] National Regulatory Research Institute, *Utility Ratemaking: The Fundamentals and the Frontier* at 2-3 (2011);
[197] PAC/1600, Dalley/6.

with the customer's receipt of the benefits of the project.[198] The parties seem to suggest that allowing cost recovery when the project begins serving customers is somehow harmful.[199] To the contrary, allowing such cost recovery is consistent with regulatory principles (*e.g.*, the matching principle), creates rates that more accurately reflects the cost of serving customers, and provides appropriate price signals to customers.

Staff also expresses concern that the Company is "cherry-picking" items to include in rates, without also examining offsetting revenues.[200] But this argument is unpersuasive. Because the Mona-to-Oquirrh transmission project will go into service during the test period, the Company is not "cherry-picking" items from an unexamined future period to include in rates. All known, measurable, and reasonably certain expenses and revenues (other than other capital additions not expected to be complete before December 31, 2012) were included in the test year and reviewed by the parties. In fact, it is the other parties who are "cherry-picking" by contesting the inclusion of the fixed costs in rate base, while allowing inclusion of the transmission project in the GRID topology beginning in May 2013.

ICNU also argues that the Company could avoid regulatory lag by filing its rate case at a later date so the Mona-to-Oquirrh transmission project would be completed before the forecast test period.[201] But contrary to ICNU's assertions, the Company does not have the discretion to file a general rate case at any time. Under the TAM guidelines, a general rate case must be filed by March 1 to accommodate a January 1 effective date.[202] Thus, unless the Commission waived the guidelines, the Company could not file a 2012 general rate case

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[198] *Id.*
[199] ICNU/111, Deen/4.
[200] Staff/1000, Johnson/3.
[201] ICNU/111, Deen/3-4.
[202] *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism*, Order No. 09-274, Appendix A at 13 (June 16, 2009).

after March 1, 2012. Given these constraints, the Company could not avoid "regulatory lag" simply by filing its rate case later. Under the current calendar year cycle for general rate cases in Oregon, the Company's next opportunity to file for the inclusion of the Mona-to-Oquirrh transmission project in rates would be March 1, 2013, for a January 1, 2014, rate effective date. Under that alternative, the project would have already been serving customers and providing net power cost and reliability benefits for approximately eight months by the time recovery of the costs of the project would begin.

7. Conclusion

The Commission should approve the Company's proposal to recover its investment in the Mona-to-Oquirrh transmission project because it will be used and useful at the time the proposed tariff rider goes into effect. The Company's proposal is consistent with Commission precedent and accommodates the parties' arguments in past cases concerning the used and useful standard, while allowing the Company to timely recover an investment in a transmission line that is necessary to continue to provide safe, reliable, and adequate service to its customers. 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.

V. CONCLUSION

As demonstrated in this brief, PacifiCorp has presented substantial evidence showing that its investment in emissions controls at its thermal generating plants were prudent and cost-effective, and are currently used and useful to serve customers. The Company has further demonstrated that a PCAM is necessary to address the Company's chronic under-recovery of NPC and to comply with SB 838. The Company has also shown that it is appropriate to allow recovery of the Company's investment in the Mona-to-Oquirrh transmission project through a separate tariff rider that will go into effect once the project goes into service and the final costs of the project are reviewed. Finally, the Stipulating Parties settled all other issues in this case and agree that the partial stipulation results in fair, just, and reasonable rates. PacifiCorp therefore respectfully requests that the Commission issue an order:

- Authorizing PacifiCorp to recover its investments in emissions controls at its coal-fired generating plants;
- Approving a PCAM that allows full recovery of the difference between the Company's forecast and actual prudent NPC;
- Authorizing the Company to file a special tariff rider that allows recovery of the Company's investment in the Mona to Oquirrh transmission project when the project goes into service; and
- Approving and adopting the partial stipulation between the Company, Commission Staff, the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and the Kroger Co.

Respectfully submitted this 4th day of October, 2012.

By: ______________________
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APPENDIX A
LIST OF EXHIBITS BY SUBJECT—CONTESTED ISSUES

EMISSIONS CONTROLS	
EXHIBIT NO.	**DESCRIPTION**
PAC/500, Teply	Direct Testimony of Chad A. Teply
PAC/501	Overview of PacifiCorp's Environmental Control Plan – Company Operated Facilities
PAC/502	Known Regulatory Drivers and Environmental Projects
PAC/503	Mercury Control Projects – Company Owned Facilities
PAC/504	List of CCR Projects Included in 10-Year Plan (2012-2021)
PAC/505	Emerging Environmental Regulations Overview
PAC/506	MEHC Comments on Proposed Coal Combustion Residuals Rule
PAC/507	MEHC Comments on Proposed Clean Water Act Section 316(b) Rule
PAC/600, Ralston	Direct Testimony of Dana M. Ralston (Thermal O&M)
PAC/1400, Woollums	Reply Testimony of Cathy S. Woollums
PAC/1401	Comments on DEQ Regional Haze BART Determinations for Wyoming Coal-Fired Power Plants (August 4, 2009)
PAC/1402	Earthjustice Comments on Wyoming Draft State Implementation Plans for Regional Haze (December 7, 2010)
PAC/1403	Naughton BART Permit Decision, Wyoming Air Quality Division and Wyoming Department of Environmental Quality (December 31, 2009)
PAC/1404	Section 309 State Emissions Profiles
PAC/1405	Excerpts from PacifiCorp's Annual Report of the Status of Commitments – 2007 through 2011.
PAC/1500, Teply	Reply Testimony of Chad A. Teply
PAC/1501	Compliance Timelines for Naughton Units 1 and 2, and Hunter Units 1 and 2
PAC/1900, Woollums	Surrebuttal Testimony of Cathy S. Woollums
PAC/1901	Wyoming Department of Environmental Quality BART Analysis Request for Naughton
PAC/1902	Wyoming Department of Environmental Quality, Air Quality Division, Draft BART Rules
PAC/1903	Wyoming Department of Environmental Quality, Air Quality Division, Final BART Rules
PAC/1904	NAAQs Preliminary SO_2 Modeling Results
PAC/2000, Teply	Surrebuttal Testimony of Chad A. Teply
PAC/2001	Busbar Cost Workpapers for Dave Johnston Unit 4, Naughton Units 1 and 2, Jim Bridger Unit 3, and Wyodak
PAC/2002	BART Analyses and Applicable Permits for Naughton Units 1 and 2

EMISSIONS CONTROLS	
PAC/2003	BART Analyses and Applicable Permits for Hunter Units 1 and 2
PAC/2004	BART Analyses and Applicable Permits for Jim Bridger Unit 3
PAC/2005	BART Analyses and Applicable Permits for Dave Johnston Unit 4
PAC/2006	BART Analyses and Applicable Permits for Wyodak
PAC/2007	NO_x Reduction Technologies Study

PCAM	
EXHIBIT NO.	**DESCRIPTION**
PAC/900, Duvall/14-36	Direct Testimony of Gregory N. Duvall
PAC/901	PCAM Comparison Chart
PAC/1300, Griffith/17-18	Direct Testimony of William R. Griffith
PAC/1301	Schedule 206—Proposed PCAM Tariff (at page 31)
PAC/1700, Bird	Reply Testimony of Stefan Bird
PAC/1800, Duvall	Reply Testimony of Gregory N. Duvall
PAC/1801	Wind Variance Risk
PAC/1802	Comparison of PCAM Proposals
PAC/2200	Surrebuttal Testimony of Gregory N. Duvall

MONA-TO-OQUIRRH TRANSMISSION PROJECT	
EXHIBIT NO.	**DESCRIPTION**
PAC/700, Gerrard	Direct Testimony of Darrell T. Gerrard
PAC/1100, Dalley/14	Direct Testimony of R. Bryce Dalley
PAC/1106	Mona-to-Oquirrh Transmission Investment
PAC/1300, Griffith/15-16	Direct Testimony of William R. Griffith
PAC/1304	Transmission Investment Adjustment Proposed Rate Spread and Illustrative Tariff
PAC/1600, Dalley	Reply Testimony of R. Bryce Dalley
PAC/1601	Mona-to-Oquirrh Project Capital Expenditures and Revenue Requirement
PAC/2100	Surrebuttal Testimony of R. Bryce Dalley