

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND
TRANSPORTATION
COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT
COMPANY,

Respondent.

DOCKET UE-152253

PACIFIC POWER & LIGHT COMPANY'S POST-HEARING BRIEF

REDACTED

June 22, 2016

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I. INTRODUCTION

1 Pacific Power & Light Company (Pacific Power or the Company), a division of PacifiCorp, raised a limited—but critically important—set of rate changes and policy proposals in this proceeding that are designed to break its cycle of near-annual rate case filings. There are four key building blocks: (1) recovery of the Company’s selective catalytic reduction systems (SCRs) at Units 3 and 4 of the Jim Bridger plant; (2) reinstating previously approved, shorter depreciation lives for the Jim Bridger plant and Colstrip Unit 4; (3) a two-year rate plan, with a first-year increase of \$9.0 million, or 2.69 percent, and a second year increase of \$10.3 million, or 2.99 percent;¹ and (4) a decoupling mechanism that aligns with mechanisms now in place for other utilities and enjoys wide support from the parties.

2 In reviewing the prudence of the SCRs, the Commission’s well-established standard requires a utility’s business decision to be objectively reasonable, based on the information known or available at the time. Judged under this standard, the evidence here shows that the Company “made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.”² The Company used its expertise to devise a workable Regional Haze compliance plan with environmental regulators; developed a sophisticated economic analysis to determine the least-cost, least-risk compliance alternative; presented that analysis and the recommended SCR investment in the Company’s 2013 Integrated Resource Plan (IRP) and state pre-approval processes; negotiated an innovative and flexible engineering, procurement and construction (EPC) contract to reduce customer risk; monitored the continuing economic viability of the SCRs; and managed the project to completion on-time and under-budget. Jim Bridger Units 3 and 4 continue to provide low-cost,

¹ McCoy, Exh. No. SEM-6T 3 Table 1 and Table 2. The components of the Company’s case are set forth in Appendix A.

² *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 ¶19 (Apr. 7, 2004).

reliable power to Washington, and installation of the SCRs allows the units to remain fully compliant with Regional Haze requirements.

3 Staff and Sierra Club challenge the prudence of the Company’s decision. But neither disputes that the Company was prudent in May 2013 when it made the decision to proceed and executed its EPC contract for the SCRs. Instead, the parties challenge the Company’s analysis seven months later, when the Company issued the full notice to proceed (FNTP) under the EPC contract. Staff’s and Sierra Club’s positions ignore a critical fact—Pacific Power prudently negotiated the FNTP procedure, which is an atypical contractual provision, because Pacific Power *wanted* the opportunity to re-evaluate the decision to invest. It is absurd to claim that Pacific Power did not capitalize on the very opportunity it negotiated to have. Furthermore, Staff’s and Sierra Club’s analyses are flawed, inconsistent, and appear designed to justify a disallowance instead of supporting a fair prudence review. The parties also oversimplify the complexity of the Company’s task of complying with fast-approaching Regional Haze deadlines in the most cost-effective manner possible. Neither considers the broader consequences of terminating the EPC contract at a point when meeting mandated compliance deadlines through natural gas conversion would not be possible.

4 Second, to manage future compliance risks from ever-increasing state and federal regulation of greenhouse gas emissions, the Company proposes reinstating its pre-2008 depreciable lives for the Jim Bridger plant and Colstrip 4, ending in 2025 and 2032, respectively. Reducing the plants’ depreciable lives will allow greater resource planning flexibility to respond to these regulations, while mitigating potential rate impacts from stranded investments. The Commission has discretion to set depreciation rates based on policy concerns and should exercise this authority to prevent future rate shock from the combined impact of potential early plant retirement and the acquisition of new alternative generation resources. Accelerating

depreciation now allows the Commission to act with only a moderate immediate rate impact.

5 Third, this limited-issue filing proposes a two-year rate plan with rate increases of less than three percent, with the Company foregoing another rate case for a minimum of approximately two years. Similar to other Commission-approved rate plans, end-of-period rate base is used to address regulatory lag. Approval of the Company's rate plan benefits customers through predictable, moderate rate increases and provides a strong incentive for cost control. Furthermore, consistent with Commission Staff's proposal in the Company's 2013 general rate case, this limited-issue proceeding reduces regulatory lag by allowing recovery of \$300 million in new capital projects on an expedited basis. Staff supports the Company's framework, agreeing that it is consistent with Commission precedent and beneficial to customers.

6 Fourth, the Company's proposed decoupling mechanism follows the Commission's policy guidance, and all parties support its key components. Approval of decoupling supports the Company's conservation efforts and recovery of fixed costs as the Company experiences low or negative load growth. The decoupling mechanism also includes an earnings test that ensures that the Company's proposed rate plan does not result in rates that are unjust or unreasonable.

II. SELECTIVE CATALYTIC REDUCTION SYSTEMS

A. The Prudence Standard Requires Reasonableness and Prohibits Hindsight Review.

7 To determine prudence, the Commission reviews whether the utility made a reasonable business decision in light of the facts and circumstances that were known or that reasonably should have been known at the time the decision was made.³ The Commission has articulated four specific factors it reviews in determining prudence.⁴

³ *Id.*

⁴ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048, *et al.*, Order 08 ¶409 (May 7, 2012).

8 First, a utility must establish the need for the resource and determine how to meet the need in a cost-effective manner. Second, a utility must analyze available alternatives using up-to-date information. When analyzing alternatives, the Commission has recognized that “[s]uch decisions are complex and involve consideration of a host of factors” and that one alternative “may be superior to others by some measures,” while another alternative “may be more favorable considering other, equally important criteria.”⁵ All that is required is that the utility undertake a “careful, thorough and detailed examination of the leading” alternatives and that the ultimate decision be reasonable.⁶ In other words, prudence does not require a single, optimum decision; rather, a utility can make a reasonable business decision “among several alternatives, any one of which the Commission might find prudent.”⁷

9 Third, a utility must keep management informed and involved in the process so that the decision is “appropriately made by a senior executive, consistent with Company policy.”⁸ Fourth, the utility must keep adequate contemporaneous records that will allow the Commission to evaluate the decision-making process.⁹ The Commission does not engage in hindsight review—the prudence inquiry is limited to information known or available to the utility when it made the prospective decision.¹⁰ Adequate documentation allows the Commission “to follow the utility’s decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.”¹¹

⁵ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704, *et al.*, Order 11 ¶337 (Apr. 2, 2010).

⁶ *Id.*

⁷ *Id.*

⁸ *WUTC v. Pac. Power & Light Co.*, Docket UE-130043, Order 05 ¶¶261, 262 (Dec. 4, 2013) (“Pacific Power’s 2013 GRC Order”).

⁹ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048, *et al.*, Order 08 ¶409 (May 7, 2012).

¹⁰ *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 ¶65 (May 13, 2004).

¹¹ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048, *et al.*, Order 08 ¶409 (May 7, 2012).

B. The Company's Economic Analysis Was Comprehensive and Conclusive—the SCRs were the Least-Cost, Least-Risk Compliance Alternative.

10 Jim Bridger Units 3 and 4 are coal-fueled generation units with a combined 1,050 MW of capacity that are critical to Pacific Power's ability to ensure reliable and affordable service for Washington customers.¹² In 2008, the Company began assessing Regional Haze compliance options for these units, with the goal of minimizing costs and risks to customers.¹³ Through a combination of litigation and diligent negotiation with environmental regulators in Wyoming, in late 2010 the Company secured a schedule allowing Units 3 and 4 to comply with applicable emission standards by 2015 and 2016, respectively.¹⁴ This permitted potential installation of the SCRs during a scheduled major maintenance outage, reducing compliance costs.¹⁵ Wyoming's requirements were independent of any federal obligation, never questioned by the U.S. Environmental Protection Agency (EPA), and approved by the EPA without change.¹⁶

11 In 2012, the Company developed its economic analysis of compliance options. Using its System Optimizer (SO) Model, which is also used for IRPs, the Company analyzed many different alternative compliance options, including SCRs, retiring and replacing the units, and converting one or both units to natural gas.¹⁷ The Company's analysis compared these options under a range of scenarios using different gas curves and carbon prices.¹⁸ Based on an assessment of each option's economic and risk profile, the Company determined that early retirement of these units was not a viable option.¹⁹ Rather, the viable options were either to

¹² Teply, Exh. No. CAT-40CT 8:22-9:7; *see* Link, Exh. No. RTL-1CT 14:9-18:2; Twitchell, Exh. No. JBT-10C at 7.

¹³ Teply, TR. 513:1-18; Teply, Exh. No. CAT-27CCX; Teply, Exh. No. CAT-32CX.

¹⁴ Teply, Exh. No. CAT-24.

¹⁵ Teply, TR. 513:1-18.

¹⁶ Teply TR. 481:24-482:5; Teply, Exh. No. CAT-25; Fisher Exh. No. JIF-28CX at 4; Fisher, Exh. No. JIF-30CX.

¹⁷ Link, Exh. No. RTL-1CT 2:23-4:4, 5:20-6:3.

¹⁸ Link, Exh. No. RTL-1CT 9:3-13.

¹⁹ Link, Exh. No. RTL-1CT 4:7-5:6, 25:1-26:3.

invest in the SCRs or convert the units to natural gas.²⁰ The analysis showed that the SCRs were the most cost-effective compliance option by [REDACTED].²¹ While the Company's economic analysis focused on the base case present value revenue requirement differential (PVRR(d)) for each option, the analysis was not limited to this metric.²² The Company also reviewed the full range of scenarios to assess both quantitatively and qualitatively which compliance option was least-cost and least-risk.²³

C. The Company's Analysis was Tested in the Fully Litigated Pre-Approval Cases.

12 In August 2012, the Company filed for a certificate of public convenience and necessity (CPCN) in Wyoming and for SCR pre-approval in Utah.²⁴ Sierra Club participated in both cases, raising many of the same issues it now raises in this case.²⁵ The Company's SCR analysis was fully vetted and refined in these pre-approval proceedings.²⁶

13 In February 2013, the Company comprehensively updated its analysis using its September 2012 Official Forward Price Curve (OFPC) and its January 2013 long-term fueling plan for the Jim Bridger plant.²⁷ The updated results decisively favored the SCRs, this time by [REDACTED].²⁸ Because natural gas and carbon prices are the primary drivers in the economics of the SCRs, the Company developed a breakeven price for each.²⁹ This analysis used precise regressions that allowed the Company to continuously monitor market changes affecting the economics of the SCRs without having to re-create its analysis for changes in these two factors.³⁰

²⁰ Link, Exh. No. RTL-1CT 4:7-5:6.

²¹ Twitchell, Exh. No. JBT-10C 4.

²² Link, Exh. No. RTL-1CT 13:2-14:8.

²³ Link, Exh. No. RTL-1CT 9:3-13, 18:4-23, 22:1-24:12; Link, TR. 642:2-12, 644:2-10, 657:10-658:24.

²⁴ Teply, Exh. No. CAT-1CT 13:13-14:10; Teply, Exh. No. CAT-14CT 7 Figure 1.

²⁵ Teply, Exh. No. CAT-40CT 4:4-8.

²⁶ Teply, Exh. No. CAT-40CT 3:13-23, 4:4-8.

²⁷ Teply, Exh. No. CAT-40CT 3:19-23; Twitchell, Exh. No. JBT-10C 22.

²⁸ Teply, Exh. No. CAT-40CT 3:19-23.

²⁹ Link, Exh. No. RTL-1CT 8:8-21, 18:4-21:2; Link, Exh. No. RTL-9C; Link, Exh. No. RTL-10C.

³⁰ Link, Exh. No. RTL-15CT 2:10-21; Link, TR. 636:21-637:4; Twitchell, Exh. No. JBT-1CT 24:1-8.

14 In May 2013, both the Wyoming and Utah commissions approved the SCRs. The Wyoming commission found that SCRs were the “most preferable option,” “in the public interest,” and that “it is inescapable that the Company’s course of action, taken in the context of increased ratepayer costs associated with delay, is reasonable.”³¹ The Utah commission found that the Company’s economic analysis “not only demonstrates the Project is favored in six of nine cases, but substantially so;” and, in rejecting Sierra Club’s claims, concluded that there was “no compelling evidence, arguments, or analysis shifting the economics to favor an alternative strategy to comply with the Wyoming [State Implementation Plan] requirements.”³²

D. The Company’s SCR Analysis was Subject to Further Review in the 2013 IRP.

15 The Company incorporated its updated SCR analysis from February 2013 into its 2013 IRP, filed in April 2013, with minor updates that increased the benefits of the SCRs.³³ The Company’s analysis in the 2013 IRP was based solely on economics, without any bias in favor of the SCRs.³⁴ Indeed, while the Company’s economic analysis in the 2013 IRP supported SCRs for Jim Bridger Units 3 and 4, that same IRP analysis supported decisions to close the Carbon plant and convert Naughton Unit 3 to natural gas.³⁵ According to Staff, the Company “sets the bar for other utilities with the quality and depth of its IRP process.”³⁶

E. The Company’s Rigorous Analysis Informed its Decision to Invest in the SCRs and Execute the EPC Contract in May 2013.

16 In May 2013, the Company conducted a final review of the SCR investment.³⁷ By this

³¹ *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013).

³² *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct SCRs on Jim Bridger Units 3 and 4*, Docket 12-035-92, Report and Order at 32 (May 10, 2013) (“Utah Pre-Approval Order”).

³³ Link, Exh. No. RTL-1CT 2:25-27; Teply, Exh. No. CAT-1CT 12:8-11; Teply, Exh. No. CAT-40CT 4:1-3.

³⁴ Crane, TR. 599:16-600:1; Teply, Exh. No. CAT 21C 3.

³⁵ PacifiCorp’s 2013 IRP at 3, 38; Teply, TR. 522:21-24.

³⁶ Teply, Exh. No. CAT-15 1.

³⁷ Teply, Exh. No. CAT-40CT 4:9-14; Twitchell, Exh. No. JBT-10C.

point, the Company’s analysis had been fully reviewed in two litigated cases and as part of the public process for the Company’s 2013 IRP. These processes generated voluminous analysis and documentation—literally thousands of pages—supporting the reasonableness of the SCRs, which the Company reviewed and synthesized in its decision memoranda.³⁸ The evidence available in May pointed decisively to the SCRs as the least-cost, least-risk option.

17 Based on a review of all of the available analysis, the Company’s President and Chief Executive Officer authorized the SCRs on May 31, 2013, in accordance with the Company’s governance policies.³⁹ The Company made a “careful, thorough and detailed examination of the leading” alternatives, and documented this process to make its decision-making clear.⁴⁰

18 To minimize customer risk associated with the SCRs, the Company negotiated an innovative EPC contract allowing the Company to delay significant investment in the SCRs to December 1, 2013. This was the latest date possible for cost-effective, timely installation of the SCRs.⁴¹ This structure included a limited notice to proceed (LNTP) in May 2013 and a FNTP in December 2013.⁴² The FNTP allowed the Company to continue to monitor the economics of the SCR projects between May and December 2013 and complete the regulatory approval processes. But reasonable business practices neither allowed nor required the Company to continually re-create its entire SCR analysis as market dynamics constantly changed. Such an approach would paralyze the Company’s ability to act—a result that would have been clearly imprudent given the multi-year construction timeline, the impending compliance deadlines, and the clearly favorable

³⁸ Teply, Exh. No. CAT-40CT 4:9-14; Teply, Exh. No. CAT-39CX.

³⁹ Teply, Exh. No. CAT-14CT 9:8-10:9, 11:5-13; Teply, TR. 468:3-470:5, 532:9-533:2.

⁴⁰ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704, *et al.*, Order 11 ¶337 (Apr. 2, 2010); *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048, *et al.*, Order 08 ¶409 (May 7, 2012).

⁴¹ Teply, Exh. No. CAT-14CT 13:12-16; Teply, Exh. No. CAT-40CT 4:15-21.

⁴² Teply, Exh. No. CAT-1CT 14:15-20; Twitchell, Exh. No. JBT-10C 31.

economics.⁴³ The Company's post-May 2013 assessment was informed by the knowledge that, for a project of this magnitude and regulatory complexity, the Company could not change compliance options without incurring substantial additional costs and implementation delays.⁴⁴

19 Although the Company's prudent negotiation of the EPC contract provided for a delayed FNTP deadline, the material date for determining the Company's prudence is May 2013, when the Company chose to move forward with the SCRs and executed the EPC contract.⁴⁵ While it is relevant to consider how the Company managed the first stage of the EPC contract from the LNTP in May 2013 to the FNTP in December 2013, this consideration must take into account the Company's significant review process in May 2013 and the fact that the structure of the EPC contract itself is evidence of the Company's prudence.⁴⁶ Importantly, no party in this case challenges the prudence of the decision to execute the EPC contract in May 2013.⁴⁷

F. The Company Continued to Monitor the Economics of the SCRs After May 2013.

20 Before issuing the FNTP, management personnel were in frequent contact and regularly monitoring the economics of the SCR investment as inputs and assumptions in the SCR analysis changed over time.⁴⁸ Between May and December 2013, however, nothing indicated that the substantial SCR benefits had eroded or that natural gas conversion had become the more economic compliance alternative.⁴⁹

1. Natural Gas Prices Remained Above the Breakeven Price.

21 The breakeven analysis developed during the pre-approval cases allowed the Company to

⁴³ Teply, Exh. No. CAT-40CT 7:6-8:10.

⁴⁴ Teply, Exh. No. CAT-40CT 6:12-7:2.

⁴⁵ Teply, Exh. No. CAT-14CT 13:8-20.

⁴⁶ Teply, Exh. No. CAT-14CT 13:8-20, Link, TR. 667:12-15.

⁴⁷ Twitchell, TR. 701:15-19.

⁴⁸ Teply, Exh. No. CAT-40CT 4:22-5:18; Link, Exh. No. RTL-15CT 3:4-10; Teply, TR. 462:4-463:2, 464:4-465:7, 533:23-534:4, 534:19-25, 554:7-25; Link, TR. 688:9-11; Link, Exh. No. RTL-16CX.

⁴⁹ Link, Exh. No. RTL-15CT 4:3-8; Teply, TR. 535:3-10; Link, TR. 659:23-660:8.

rapidly reassess the SCR investments in light of changes in forward gas prices.⁵⁰ At the time the Company issued the FNTP, the Company's most recent OFPC (dated September 2013) had a nominal levelized price of \$5.35 per million British Thermal Units (mmBtus), which was well above the SCRs breakeven price of [REDACTED].⁵¹ Even after accounting for declining natural gas prices, the SCRs remained favorable by over [REDACTED].⁵²

22 After the September 2013 OFPC, there were no indications that prices had fallen below the breakeven point.⁵³ In late October 2013, the Company received a forecast from a third-party consultant with a nominal levelized price of [REDACTED]—even higher than the September 2013 OFPC.⁵⁴ This consultant's price curve had decreased only [REDACTED], between May and October 2013.⁵⁵ The other consultant curve received between September 30 and December 1 showed a [REDACTED] relative to the same consultant's August forecast.⁵⁶ Although the Company does not make long-term resource decisions based on isolated consultant forecasts, this data demonstrates the reasonableness of the Company's continued reliance on its September 2013 OFPC, especially given the inherent uncertainty in long-term forecasts.⁵⁷ Although natural gas prices fell between May and December 2013, the Company recognized that natural gas prices are volatile, cannot trend downward indefinitely, and could reasonably rise to higher than the base case projections.⁵⁸ Additionally, the Company's

⁵⁰ Link, Exh. No. RTL-15CT 2:10-21; Link, TR. 640:12-23.

⁵¹ Link, Exh. No. RTL-1CT 20:3, 20:14-21.

⁵² Link, Exh. No. RTL-1CT 20:14-21.

⁵³ Link, TR. 691:25-693:9.

⁵⁴ Link, Exh. No. RTL-11CT 18:5-14.

⁵⁵ Link, Exh. No. RTL-11CT 18:5-14; Twitchell, Exh. No. JBT-22CCX 1; Pacific Power's Response to Bench Request No. 6.

⁵⁶ Link, TR. 687:21-688:4; Link, Exh. No. RTL-11CT 18:5-14; Twitchell, Exh. No. JBT-22CCX 2; Pacific Power's Response to Bench Request No. 6.

⁵⁷ Link, Exh. No. RTL-11CT 17:5-18:2; Link, TR. 668:22-669:11.

⁵⁸ Link, Exh. No. RTL-15CT 4:9-17; Link, TR. 658:21-24.

SCR analysis accounted for these risks through the use of multiple scenarios.⁵⁹ The changes in forward natural gas prices between May and December 2013 did not render the SCRs uneconomic.

2. EPC Contract Savings Increased the SCR Benefits.

23 The Company's SCR analysis assumed that the Company's share of the EPC contract costs would be [REDACTED].⁶⁰ By the time the FNTP was issued, however, the Company knew that the actual costs of the EPC contract were only [REDACTED].⁶¹ This [REDACTED] reduction in EPC costs directly increased the benefits of the SCRs relative to natural gas conversion. On a revenue requirement basis, accounting for this known cost savings increased the SCR benefits to over [REDACTED] as of December 1, 2013.⁶²

3. Changes in Coal Costs did not Offset SCR Benefits.

24 The Company did not develop a breakeven analysis for coal costs because those costs are typically not as volatile as natural gas and carbon prices.⁶³ Instead, the Company reviewed the update to the Bridger Coal Company (BCC) mine plan and forecasts of third-party coal costs prepared in October 2013 as part of the Company's 10-year budget process.⁶⁴ This information reflected a change in the use of the surface and underground mines from the mine plan used in the Company's SCR analysis, but did not translate into a substantial change in costs.⁶⁵ While BCC's cash costs (*i.e.*, the variable costs of production) increased, that increase was substantially offset by capital cost savings.⁶⁶ In fall 2013, the Company also knew that its contract with the

⁵⁹ Link, Exh. No. RTL-1CT 23:11-24:12.

⁶⁰ Teply, Exh. No. CAT 14CT 15 Confidential Figure 3.

⁶¹ Teply, Exh. No. CAT 14CT 15 Confidential Figure 3; Teply, TR. 467:8-25.

⁶² Link, Exh. No. RTL-15CT 5:1-2; Link, TR. 655:22-656:25.

⁶³ Link, TR. 641:3-18, 642:18-643:6.

⁶⁴ Teply, Exh. No. CAT-40CT 5:1-2; Crane, TR. 609:16-23, 625:4-9.

⁶⁵ Ralston, Exh. No. DR-1CT 8:5-11.

⁶⁶ Crane, Exh. No. CAC-1CT 3:1-3, 7:7-13; Crane, TR. 608:18-23. Cash costs are variable production costs.

plant's primary third-party coal supplier was set to expire.⁶⁷ Based on market analysis of third-party coal costs conducted in fall 2013 as part of its 10-year budget process, [REDACTED]

[REDACTED].⁶⁸

25 Accounting for both the moderate increase in BCC costs and the [REDACTED] in third-party costs, coal costs for the Jim Bridger plant increased by roughly [REDACTED] percent between January and October 2013, or approximately [REDACTED].⁶⁹ With SCR benefits of over [REDACTED] as of December 1, 2013, applying this offset (with no adjustment to the two-unit scenario) results in nearly [REDACTED] in SCR benefits.

26 Increasing coal costs affect both the SCR scenario (*i.e.*, the four-unit scenario) and the natural gas conversion scenario (*i.e.*, the two-unit scenario) because in both scenarios BCC would continue to supply the Jim Bridger plant with coal.⁷⁰ The Company's analysis reasonably assumes that the increase in coal costs for the two-unit scenario would be at least as much as the increase for the four-unit scenario, because the BCC mine is subject to economies of scale and production decreases substantially in a two-unit scenario.⁷¹ A [REDACTED] increase in the two-unit scenario is [REDACTED].⁷² To calculate the differential between the SCR and natural gas conversion scenarios, this two-unit increase is subtracted from the four-unit increase [REDACTED]

⁶⁷ Crane, Exh. No. CAC-1CT 9:8-14.

⁶⁸ Crane, Exh. No. CAC-1CT 9:16-22.

⁶⁹ Crane, TR. 591:1-4; Ralston, Exh. No. DR-2C ([REDACTED] for 2014-2030 based on 2015 IRP); Ralston, Exh. No. DR-4C ([REDACTED] for 2016-2030 based on 2015 IRP); Crane, Exh. No. CAC-2C ([REDACTED] for 2014-2024 based on October 2013 mine plan and 10-year budget). Total plant fueling costs in the SCR analysis were [REDACTED], so an increase of [REDACTED] produces [REDACTED] in additional costs. Ralston, Exh. No. DR-2C. The parties each presented their coal adjustments in a different way, making a direct comparison of the numeric adjustments difficult. The Company's calculations were on revenue requirement basis and the October 2013 calculations only reflect the 10-year horizon of the budget. The calculations included here are based on the Company's various calculations of the percentage change in coal costs applied to the overall fuel costs included in the SCR analysis.

⁷⁰ Link, Exh. No. RTL-1CT 6:16-8:4.

⁷¹ Ralston, Exh. No. DR-1CT 12:10-14; Crane, Exh. No. CAC-1CT 13:5-11; Crane, Exh. No. CAC-1CT 11:12-16, 12:14-20; Twitchell, Exh. No. JBT-37C 22:19-23:1; Ralston, Exh. No. DR-7CX 7:4-5; Twitchell, Exh. No. JBT-28HCT 23:19-20.

⁷² Ralston, Exh. No. DR-2C.

██████████, resulting in a change in SCR benefits of only ██████████ related to coal costs. In short, the EPC contract savings nearly offset the coal cost increase.

27 The reasonableness of the Company's assumption of two-unit coal costs was confirmed when the Company demonstrated in its supplemental rebuttal testimony that costs under a two-unit scenario would have increased by much more than the costs of the four-unit scenario.⁷³

Two-unit costs would have increased by up to ██████████ — ██████████ ██████████ as of December 1, 2013.⁷⁴

4. The Company's Carbon Price Assumptions Remained Reasonable.

28 The Company also determined that none of its third-party forecasts projected increases in carbon costs associated with President Obama's 2013 announcement of the Clean Power Plan.⁷⁵

The expert forecasts remained unchanged throughout 2013 and verified the reasonableness of the carbon assumptions in the SCR analysis, which have not been challenged in this case.⁷⁶

5. There Was No Change Between May and December 2013 That Triggered the Need to Recreate the SCR Analysis.

29 Pacific Power's lead executive in charge of the SCR project, Mr. Chad Teply, testified that he and his team regularly monitored and updated the SCR analysis based on changing market conditions between May and December 1, 2013.⁷⁷ By fall 2013, the Company's underlying SCR analysis had been thoroughly vetted and supplemented with breakeven models that permitted rapid reassessment of the economics of the SCRs.⁷⁸ Nothing in fall 2013 indicated that there were material changes in any input or assumption that would have required the

⁷³ Crane, Exh. No. CAC-1CT 12:14-13:1; Crane, Exh. No. CAC-3C; Crane, Exh. No. CAC-13CCX 4.

⁷⁴ Crane, Exh. No. CAC-1CT 12:14-13:1.

⁷⁵ Link, Exh. No. RTL-11CT 29:22-31:2.

⁷⁶ Link, Exh. No. RTL-11CT 29:22-31:2; Link, TR. 676:17-677:18, 679:8-680:20.

⁷⁷ Teply, Exh. No. CAT-40CT 4:22-5:18; Link, Exh. No. RTL-15CT 3:4-10; Teply, TR. 462:4-463:2, 464:4-465:7, 533:23-534:15, 534:19-25, 554:7-25.

⁷⁸ Link, TR. 643:10-644:20, 645:14-646:17.

Company to completely re-calculate the SCR benefits.⁷⁹ For these reasons, the Company did not conduct an entirely new SCR analysis using its SO Model before issuing the FNTP.

30 Similarly, although the Company prepared updated internal memoranda analyzing the FNTP, these documents were not on a scale comparable to the original memoranda prepared before execution of the EPC contract in May 2013.⁸⁰ Consistent with reasonable business practice, to support the FNTP, the Company relied on its original documentation for materially unchanged issues, along with supplemental memoranda addressing new issues.

G. Before Issuing the FNTP, the Company Conducted the Analysis Required by the Commission in its 2013 IRP Acknowledgment Letter.

31 In its 2013 IRP acknowledgement letter, the Commission directed the Company to construct various price curves for “carbon regulation representing the range of standards that the EPA could impose” and “natural gas that are more closely aligned with current forward prices” and include this analysis in its 2013 IRP Update.⁸¹ The Commission requested these curves to allow for a more detailed sensitivity analysis to determine the point at which carbon and gas prices would make gas conversion more economical, and noted that the Company should not move forward with the SCRs until this additional analysis was completed.⁸²

32 As explained in the Company’s 2013 IRP Update, the Company’s breakeven analysis developed as part of the Wyoming and Utah pre-approval cases provided the precise analysis the Commission requested.⁸³ Thus, when the Company issued its FNTP on December 1, 2013, it had already performed the analysis requested by the Commission and used the results of that analysis

⁷⁹ Teply TR. 460:13-17, 463:15-25, 471:4-10,

⁸⁰ See Teply, TR. 548:18-549:21, 550:16-551:1.

⁸¹ Link, Exh. No. RTL-14CX 4.

⁸² Link, Exh. No. RTL-14CX 4.

⁸³ Link, Exh. No. RTL-11CT 29:3-18; Twitchell, Exh. No. JBT-20CCX 13.

to inform its decision to issue the FNTF.⁸⁴

33 The Company's 2013 IRP Update also reflected the other information sought by the Commission's acknowledgment letter (*i.e.*, updated natural gas curves and third-party sources demonstrating that carbon prices had not increased).⁸⁵ The Company's compliance with the acknowledgement letter is confirmed by Attachment C to Staff's briefing packet for the 2015 IRP, summarizing areas of non-compliance with the 2013 acknowledgement letter—without any mention of deficiencies in the coal analysis in the IRP Update.⁸⁶

H. Staff's Analysis Contains Mathematical Errors, Flawed Assumptions, and Hindsight Review.

34 Staff clarified at hearing that it contends the Company was imprudent on December 1, 2013, when it issued the FNTF despite coal cost increases, and imprudent again on January 1, 2014, when it did not terminate the EPC contract despite the lower gas prices reflected in the December 2013 OFPC.⁸⁷ Staff's attempt to push back the prudence determination to January 1, 2014—seven months after the EPC contract was signed—constitutes hindsight review.

35 In addition, Staff's conclusions are based on erroneous analysis that, when corrected, bolsters the Company's case in support of the SCR investments. Importantly, none of the problems in Staff's analysis relate to SO modeling; Staff testified that it had access to all of the information and tools necessary to analyze and calculate its adjustments outside the SO Model.⁸⁸

⁸⁴ Link, Exh. No. RTL-15CT 3:11-17.

⁸⁵ Link, Exh. No. RTL-15CT 3:11-17; Twitchell, Exh. No. JBT-20CCX 3, 6, and 9 (updating carbon price forecasts); Twitchell, Exh. No. JBT-20CCX 10 (showing September and December 2013 OFPC above breakeven).

⁸⁶ Twitchell, Exh. No. JBT-21CX 3. In addition, the 2013 IRP Update informed the Commission that the Company had issued the FNTF for the Jim Bridger SCRs. Twitchell, Exh. No. JBT-21CX 7. Staff testified that it was unaware of this fact until this case was filed, incorrectly implying that the Company had omitted this information from the IRP Update. Twitchell, Exh. No. JBT-1CT 25:14-19.

⁸⁷ Twitchell, TR. 703:23-704:6.

⁸⁸ Twitchell, Exh. No. JBT-1CT 33:5-8; *see also*. Link, TR. 639:19-640:4, 695:17-696:2. Staff never sought access to the SO Model in this case, nor did Staff avail itself of the opportunity to use the model in the Company's 2013 IRP proceeding. Link, TR. 694:14-695:11; Twitchell, TR. 742:16-743:8 (Mr. Twitchell never clearly stated he had requested access).

1. Staff's Coal Cost Calculations are Inaccurate.

a. Staff's Adjustment Contains a Clear Mathematical Error.

36 Staff now agrees that the Company reasonably relied on its September 2013 OFPC to assess the SCR benefits before issuing the FNTP, which yields SCR benefits of [REDACTED].⁸⁹ Staff claims that these benefits are offset by its [REDACTED] adjustment for increased coal costs and therefore, based on coal costs alone, natural gas conversion was the least-cost option on December 1, 2013.⁹⁰ But Staff's adjustment contains a mathematical error that, when corrected, reduces Staff's adjustment by [REDACTED].⁹¹ Making no other changes to Staff's analysis and correcting only its math error reduces its adjustment to [REDACTED].⁹²

37 Staff adjustment is based on a comparison of the levelized price of coal in the January 2013 long-term fueling plan and the October 2013 mine plan.⁹³ Staff calculates the January levelized price as [REDACTED] and the October levelized price as [REDACTED].⁹⁴ Based on these prices, Staff concludes that BCC coal costs increased by [REDACTED].⁹⁵ When combined with Staff's alleged increase in third-party costs (discussed below), Staff claims a total coal costs increase of [REDACTED].⁹⁶ Staff's [REDACTED] adjustment is the result of multiplying the [REDACTED] increase by the total fueling costs included in the SCR analysis.⁹⁷ The primary basis for Staff's adjustment—the purported changes in BCC coal costs—rests entirely on Staff's calculation of levelized coal costs—a calculation that is demonstrably incorrect.

⁸⁹ Twitchell, TR. 703:11-18; 708:25-709:3; Link, Exh. No. RTL-1CT 20:14-21.

⁹⁰ Twitchell, Exh. No. JBT-28HCT 19:19-20:7.

⁹¹ Twitchell, Exh. No. JBT-41CCX.

⁹² Twitchell, Exh. No. JBT-41CCX; Twitchell, Exh. No. JBT-32C ([REDACTED]).

⁹³ Twitchell, TR. 717:11-21; Twitchell, Exh. No. JBT-28HCT 13:9-14:14.

⁹⁴ Twitchell, Exh. No. JBT-31C.

⁹⁵ Twitchell, Exh. No. JBT-31C 2.

⁹⁶ Twitchell, Exh. No. JBT-31C 2.

⁹⁷ Twitchell, Exh. No. JBT-32C. Sierra Club argues that Staff's adjustment is understated for failing to escalate capital costs. Fisher, Exh. No. JIF-24CT 7:6-10. The Company disagrees with Sierra Club's rationale, but Sierra Club's additional adjustment is largely immaterial due to the larger errors upon which Staff's adjustment is based.

38 A levelized cost is defined as the cost that, if assigned to every unit of energy produced over the analysis period, will equal the total costs discounted back to the base year.⁹⁸ Based on this well-established definition, the levelized cost is calculated by dividing the net present value (NPV) of the total costs discounted to the base year by the NPV of the total heat content (mmBtus) discounted to the base year.⁹⁹ This calculation is described in the National Renewable Energy Laboratory's (NREL) *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*, and in the System Advisory Model that was developed by NREL, the Sandia National Laboratory, and the United States Department of Energy to allow the public to calculate the levelized cost of energy.¹⁰⁰ This calculation is also how the Company calculates levelized costs.¹⁰¹ Conceptually, this formula accounts for the fact that the mmBtus in each year are different and therefore the levelization formula must weight its results to account for these differences.¹⁰²

39 Rather than using this industry standard, Staff calculated a price for each year in the analysis period, calculated the NPV of this stream of prices, and then calculated a levelized cost.¹⁰³ Essentially, Staff's levelized calculation incorrectly uses a simple average instead of a weighted average, which averages values scaled by the importance of the value. There is no mathematical basis for Staff's calculation, which results in a dramatically overstated price for the

⁹⁸ Appendix B at 2, 8; Twitchell, Exh. No. JBT-41CCX. The Company requests that the Commission take official notice of the documents in Appendix B as a "standard" that has been adopted by an "agency of the United States . . . or by a nationally recognized organization or association." WAC 480-07-495(2)(a)(iii).

⁹⁹ Appendix B at 3, 911-12; Twitchell, Exh. No. JBT-41CCX.

¹⁰⁰ Appendix B at 2-3, 8-9.

¹⁰¹ Crane, TR. 596:1-10.

¹⁰² Crane, TR. 622:3-8; Twitchell, Exh. No. JBT-41CCX. This weighting impact can be seen simply by looking to the corrected levelized price calculation for the January plan compared to the October plan. Twitchell, Exh. No. JBT-41CCX. For the January plan, Staff's methodology, although incorrect, closely approximated the correct formula because the total mmBtus in each year of the January plan are similar and so the failure to weight the mmBtus had a minimal impact. The October plan, by contrast, has widely varying mmBtus in each year and therefore Staff's failure to use the correct formula results in a grossly overstated amount.

¹⁰³ Twitchell, Exh. No. JBT-28HCT 13:9-14:14; Twitchell, Exh. No. JBT-41CCX.

October 2013 mine plan.

40 Applying the correct levelization formula to Staff's methodology results in an increase in BCC coal costs of only [REDACTED] between January and October 2013 [REDACTED] in January compared to [REDACTED] in October).¹⁰⁴ The accuracy of the Company's correction is easily demonstrated. By definition, the NPV of the total costs in each year must equal the NPV of the levelized price multiplied by the annual mmBtus.¹⁰⁵ The Company's corrected levelized price [REDACTED] adheres to this definition; Staff's erroneously calculated levelized price [REDACTED] does not.¹⁰⁶ This confirms that the Company correctly calculated the levelized price and Staff did not.

41 At hearing, Staff witness Jeremy Twitchell rejected the definition of levelized costs, claimed that he had "never seen" how to correctly calculate a levelized cost using the standard industry methodology, and argued that the methodology is "nonsensical."¹⁰⁷ Staff questioned why it is reasonable to discount the mmBtus in the levelized cost calculation, given that units of measurement do not typically change value over time in the same way as money.¹⁰⁸ But, as explained by NREL when addressing this very concern, "[e]ven though it may appear in this [levelized cost] formula that quantities are being discounted, this is actually a direct result of the algebra carried through from the previous formula in which revenues were discounted."¹⁰⁹ In other words, the discounting of the mmBtus in the denominator of the levelization formula does not indicate that those units of energy are literally being discounted.

¹⁰⁴ Twitchell, Exh. No. JBT-41CCX. This translates to an overall change of only [REDACTED]. Crane, TR. 621:3-6.

¹⁰⁵ Appendix B at 2, 8; Twitchell, Exh. No. JBT-41CCX.

¹⁰⁶ Twitchell, Exh. No. JBT-41CCX.

¹⁰⁷ Twitchell, TR. 719:4-13, 719:21-25, 720:5-10.

¹⁰⁸ Twitchell, TR. 717:24-718:15.

¹⁰⁹ Appendix B at 3, 9 ("This equation makes it appear that the energy term in the denominator is discounted. This is a result of the algebraic solution of the equation, not an indication of the physical performance of the system.").

42 Staff's adjustment relies on a mathematical technique for calculating a levelized cost that deviates from the generally accepted methodology and produces demonstrably incorrect results. Correcting only this error reduces Staff's coal adjustment to [REDACTED]—meaning that by Staff's own measure, the SCRs were beneficial by nearly [REDACTED] as of December 1, 2013.¹¹⁰

b. Staff's Adjustment Relies on Unsupported Simplifying Assumptions.

43 Staff relies on the October 2013 mine plan to forecast costs all the way to 2030, even though the October plan was a 10-year budget and the forecasts for years 2024 through 2030 were not developed or used by the Company for this purpose.¹¹¹ Staff also assumes third-party coal costs increased by [REDACTED] over the costs in the SCR analysis, based exclusively on the fact that third-party *test period* coal costs increased by [REDACTED] between the 2013 and 2014 rate cases.¹¹² The third-party cost change between those two cases does not indicate long-term changes, particularly because the contract Staff relied on expired in 2015.¹¹³ Additionally, Staff assumes that the ratio of BCC to third-party coal would be [REDACTED], respectively, for the entire analysis period based on the ratio during a single year.¹¹⁴ Based on what was known in fall 2013, the accurate ratio is [REDACTED] BCC coal to [REDACTED] third-party coal.¹¹⁵ Correcting Staff's third-party coal assumptions reduces its adjustment to just [REDACTED].¹¹⁶

¹¹⁰ Twitchell, Exh. No. JBT-41CCX; Twitchell, Exh. No. JBT-32C ([REDACTED]).

¹¹¹ Crane, Exh. No. CAC-1CT 3:11-4:6, 5:18-6:7; Crane, TR. 580:1-581:1, 581:20-582:14; 586:8-14, 588:2-589:12,

¹¹² Twitchell, Exh. No. JBT-28HCT 18:17-19:8.

¹¹³ Crane, Exh. No. CAC-1CT 9:8-14; Crane, TR. 618:8-22. Staff's third-party cost assumption is also undermined by Staff's response testimony, [REDACTED] and declared that use of information from the 2014 rate case would be improper. Twitchell, Exh. No. JBT-1CT 35:11-36:10. At hearing, Staff claimed that it changed its testimony when it learned through the Company's rebuttal testimony that Staff had incorrectly calculated the cash coal costs used in the SCR analysis. Twitchell, TR. 725:20-25. But the Company informed Staff during discovery exactly how to calculate the cash coal costs. Crane, Exh. No. CAC-1CT 15:1-16; Crane, Exh. No. CAC-4. In addition, this issue was addressed in Cindy Crane's testimony from the Utah rate case that Staff stated that it reviewed before filing response testimony.

¹¹⁴ Twitchell, Exh. No. JBT-28HCT 18:17-19:8; Crane, TR. 578:14-19.

¹¹⁵ Crane, TR. 619:8-18; Crane, Exh. No. CAC-2C.

¹¹⁶ Crane, Exh. No. CAC-1CT 9:16-20; Twitchell, Exh. No. JBT-41CCX ([REDACTED]).

c. Staff's Coal Adjustment Includes a Spreadsheet Error.

44 Staff's October 2013 mine plan model included underground mine equipment maintenance costs of ██████████ in 2028—five years after the mine closed.¹¹⁷ For perspective, the October 2013 mine plan included no costs in this category after 2022, ██████████ is nearly nine times higher than the next highest annual cost in this category, and the inclusion of ██████████ results in total materials and supplies costs for 2028 that are roughly triple the level included in the surrounding years.¹¹⁸ At hearing, Staff appeared to concede this error, while incorrectly blaming the Company for it.¹¹⁹ Independent of the adjustments discussed above, correcting this error reduces Staff's ██████████ adjustment by ██████████.¹²⁰

2. Staff's Natural Gas Price Adjustment is Improper Hindsight Review.

45 Staff testified that the Company's September 2013 OFPC was "clearly designed to reinforce the Company's decision" to invest in the SCRs "despite mounting, contradictory information that was reliable and readily available."¹²¹ Staff argued that it was therefore "crucial" to evaluate prudence based on the consultant price curves used by the Company to develop its September 2013 OFPC and that using those curves resulted in a reduction of ██████████ in SCR benefits.¹²² Staff strenuously argued that prudence must be determined as of December 1, 2013, and any information that became known after that date was irrelevant.¹²³

¹¹⁷ Crane, Exh. No. CAC-1CT 6:9-12; Twitchell, Exh. No. JBT-33C 5.

¹¹⁸ Twitchell, Exh. No. JBT-33C 5.

¹¹⁹ Twitchell, TR. 722:2-723:2. Staff claimed that the ██████████ figure was included in the documents provided during discovery. The Company's discovery documents do not, in fact, include this error—as evidenced by the fact that Sierra Club's analysis in this case has never included this error. After Staff filed its original cross-examination exhibits, the Company contacted Staff to point out that Exhibit No. DR-9CCX, which included the October 2013 mine plan spreadsheets, had numerous spreadsheet errors and incorrect figures. Twitchell, Exh. No. JBT-28HCT 16:2-3. This ██████████ error was included in Exhibit No. DR-9CCX, but is not in any of the original mine plan documents provided to Staff and Sierra Club. The Company worked with Staff to make sure Staff had all the correct spreadsheets, but this error appears to have been carried over from Staff's Exhibit No. DR-9CCX.

¹²⁰ Crane, Exh. No. CAC-1CT 6:11-12.

¹²¹ Twitchell, Exh. No. JBT-1CT 67:10-13.

¹²² Twitchell, Exh. No. JBT-1CT 28:15-19, 53:22.

¹²³ Twitchell, Exh. No. JBT-1CT 7:15, 7:20, 10:9-11, 14:1-5, 27:18-19, 28:1-4, 29:6-12.

46 Staff’s analysis incorrectly compared consultant curves calculated on a real basis to the Company’s forward price curve calculated on a nominal basis.¹²⁴ When corrected to compare forward curves on a like-for-like basis, Staff’s analysis increased the SCR benefits by [REDACTED].¹²⁵ After learning of its error, Staff proposed a new, contradictory standard that rejected the use of consultant curves, supported the use of the Company’s OFPC, and measured the Company’s prudence as of January 1, 2014.¹²⁶

47 To support its changed position, Staff claims that after the Company filed rebuttal testimony, “it became apparent to Staff that the Company came into new information regarding natural gas price forecasts between October and December 2013 that significantly improved the cost effectiveness of gas conversion.”¹²⁷ [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

¹²⁴ Link, Exh. No. RTL-11CT 13:3-7; Twitchell, TR. 707:10-708:17.
¹²⁵ Twitchell, TR. 707:20-708:17; Link, Exh. No. RTL-11CT 14:14-16.
¹²⁶ Twitchell, Exh. No. JBT-28HCT 26:19-21; Twitchell, Exh. No. JBT-39CX; Twitchell, TR. 708:18-709:3.
¹²⁷ Twitchell, Exh. No. JBT-1CT 26:8-11.
¹²⁸ Link, Exh. No. RTL-15CT 7:8-20; Link Exh. No. RTL-16.
¹²⁹ Twitchell, TR. 706:3-6; Link, Exh. No. RTL-15CT 7:8-20. At hearing, Staff claimed that it did not know that these curves were provided after the September 2013 OFPC until the Company filed rebuttal testimony. Twitchell, TR. 706:8-16. But Staff’s response testimony referred to the forecasts used to develop the September 2013 OFPC so Staff should have known which curves were received after September, based on the Company’s response to WUTC Data Request 92, which asked for all third-party curves provided to Pacific Power in 2012 and 2013. Pacific Power’s Response to Bench Request No. 6. Sierra Club relied on the exact same discovery responses but was able to discern which forecasts were received after September 2013. Fisher, Exh. No. JIF-1CT 28:1-29:8.
¹³⁰ Link, Exh. No. RTL-15CT 9:21-10:12.
¹³¹ Link, Exh. No. RTL-11CT 18:5-14; Link, Exh. No. RTL-18CX.

[REDACTED]¹³² Thus, not only was this information not new to Staff (and therefore cannot justify its reversal of position), the curves also do not “significantly improve” the natural gas conversion option.

48 Staff’s new position that the receipt of the consultant curves should have fundamentally changed the Company’s outlook on forward gas prices also ignores the Company’s prudent and comprehensive approach to determining its OFPC.¹³³ The Company does not rely on a single forecast, or even a combination of individual forecasts.¹³⁴ To depart from the Company’s well-established and prudent methodology for forecasting prices would have been unreasonable.

49 Staff also claims that it reversed its position when it learned about the termination provisions of the EPC contract.¹³⁵ But Staff admitted at hearing that it had reviewed the EPC contract before filing its response testimony.¹³⁶ In fact, Staff’s response testimony stated that the contract “details are important in determining when the Company officially made the final decision . . . thereby establishing the point in time at which prudence should be evaluated.”¹³⁷ Staff continued: “Based on the language of the EPC contract, Staff asserts that December 1, 2013, is the correct point in time for evaluating the prudence of the Bridger SCR[.]”¹³⁸ Staff’s response testimony also specifically referred to the termination penalties included in the EPC contract.¹³⁹ Staff cannot now credibly claim that the same EPC contract language that dictated a December 1 review date now dictates a January 1 review date.

¹³² Twitchell, TR. 710:10-16.

¹³³ Link, TR. 670:13-671:5.

¹³⁴ Link, TR. 681:12-684:8.

¹³⁵ Twitchell, Exh. No. JBT-28HCT 29:3-13.

¹³⁶ Twitchell, TR. 707:3-9.

¹³⁷ Twitchell, Exh. No. JBT-1CT 27:16-18.

¹³⁸ Twitchell, Exh. No. JBT-1CT 27:18-21. Staff reiterated this testimony nearly verbatim in a sworn declaration filed on April 25, 2016. Twitchell, Exh. No. JBT-40CCX 3.

¹³⁹ Twitchell, Exh. No. JBT-1CT 27:11-13; Twitchell, Exh. No. JBT-12C.

50 The record in this case demonstrates that when Staff developed and applied its original prudence standard, it possessed nearly all of the information that Staff now claims caused it to reverse position—Staff had the consultant curves, the December 2013 OFPC, and information about the EPC contract.¹⁴⁰ The only significant new information Staff received after it filed its response testimony was the knowledge that its original analysis contained an error that, when corrected, actually supported a finding of prudence.¹⁴¹

51 Staff also claims that the Company’s decision-making should have been based on the trend of declining natural gas prices—suggesting that even if prices in September or December 2013 were insufficient to support natural gas conversion, the Company should have assumed that prices would soon cross the breakeven point.¹⁴² Staff ignores the Company’s testimony that the prevailing view in late 2013 was that then-current natural prices were unsustainably low.¹⁴³ Mr. Twitchell’s prior work made the same point, when he wrote in late 2012 that natural gas prices at that time were unsustainable and that an equilibrium price was in the \$5.00/mmBtu range.¹⁴⁴ At hearing, Mr. Twitchell distanced himself from his prior work, arguing that his prediction was intended to suit the interests of the environmental community.¹⁴⁵ This rationale—that his conclusions differ depending on his audience—does not justify ignoring his own prior statements, which directly undermine his conclusions here. Mr. Twitchell also claimed that when he wrote the article at the end of 2012, the shale gas revolution was in its infancy and that by the end of 2013, it was clear that low prices were here to stay.¹⁴⁶ But Mr. Twitchell’s article states

¹⁴⁰ Link, Exh. No. RTL-15CT 7:8-20; Twitchell, Exh. No. JBT-20CCX 10; Twitchell, Exh. No. JBT-1CT 27:16-21.

¹⁴¹ Twitchell, Exh. No. JBT-26CCX.

¹⁴² Twitchell, Exh. No. JBT-28HCT 31:18-19; Twitchell, TR. 748:1-10.

¹⁴³ Link, Exh. No. RTL-15CT 4:14-17.

¹⁴⁴ Twitchell, Exh. No. JBT-23CX 11, 19.

¹⁴⁵ Twitchell, TR. 740:1-18.

¹⁴⁶ Twitchell, TR. 741:3-11.

that the revolution began in 2008.¹⁴⁷ Staff also testified at hearing that by late 2013 gas prices had stabilized.¹⁴⁸ Staff's argument for hindsight review here is based on the claim that gas prices were declining at an accelerated pace in late 2013, not that prices had stabilized.¹⁴⁹ Staff's trending argument is also undermined by the Company's March 2014 OFPC, which was *higher* than the December 2013 OFPC—a fact that Staff was aware of throughout this case.¹⁵⁰

52 Finally, even if the SCR analysis is adjusted for the December 2013 OFPC, the PVRR(d) calculation still favors the SCRs. The Company's analysis showed over ██████████ in benefits as of December 1, 2013, based on September 2013 OFPC and EPC contract savings.¹⁵¹ Reducing this by ██████████ to account for changes in coal costs based on the October 2013 mine plan decreases the SCR benefits to ██████████;¹⁵² reducing this amount for the December OFPC still results in ██████████ in favor of the SCRs,¹⁵³ without consideration of the EPC termination penalty.¹⁵⁴ Based on ██████████ in PVRR(d) benefits favoring SCRs, coupled with the Company's additional risk and scenario analysis, a reasonable utility would not have terminated the EPC contract and switched to natural gas conversion.¹⁵⁵

3. **The Costs of Natural Gas Conversion Had Increased by December 2013.**

53 Staff claims that the Company could have terminated the EPC contract and pursued natural gas conversion on December 1 or January 1 and still obtained the customer benefits of conversion.¹⁵⁶ But this claim rests on the incorrect assumption that the costs of conversion

¹⁴⁷ Twitchell, Exh. No. JBT-23CX 6.

¹⁴⁸ Twitchell, TR. 741:17-18.

¹⁴⁹ Twitchell, Exh. No. JBT-28HCT 31:14.

¹⁵⁰ Twitchell, Exh. No. JBT-19CX 10; Link, TR. 674:14-17; Twitchell, TR. 733:17-20.

¹⁵¹ Link, Exh. No. RTL-15CT 5:21-6:1.

¹⁵² As discussed above, this ██████████ figure assumes a conservative ██████████ overall increase in coal costs.

¹⁵³ Twitchell, Exh. No. JBT-28HCT 25:23 (assumes a ██████████ change for every penny change in gas prices).

¹⁵⁴ Twitchell, Exh. No. JBT-28HCT 30:3-14.

¹⁵⁵ See Link, TR. 657:14-17.

¹⁵⁶ Twitchell, Exh. No. JBT-28HCT 26:16-19.

developed in 2012 and early 2013, before the Company signed the EPC contract, accurately reflected the expected costs of conversion in December 2013 or January 2014. By December 1, 2013, the Company knew that the conversion costs in its SCR analysis were understated because in November 2013, the Company received competitive bids to convert Naughton Unit 3 to natural gas.¹⁵⁷ Those bids demonstrated that the costs of conversion would have been about [REDACTED] higher than the amount included in the SCR analysis.¹⁵⁸

54 The Company's SCR analysis assumed that natural gas conversion would be conducted on a normal project development and construction schedule so that Units 3 and 4 would be converted before the end of 2015 and 2016.¹⁵⁹ If the Company switched course in December 2013 and pursued conversion, it could not have met the 2015 and 2016 compliance deadlines.¹⁶⁰ Thus, Unit 3 would be off-line from January 1, 2016, through mid-year 2017, and Unit 4 would be off-line from January 1, 2017, through mid-year 2017.¹⁶¹ Losing Unit 3 for 18 months and losing Unit 4 for six months would cause the Company to incur significant replacement power costs and reduce its system reliability, increasing both the costs and risks of natural gas conversion.¹⁶²

4. Staff's Replacement Power Adjustment is Conceptually Flawed.

55 The Company's PVRR(d) calculation correctly accounted for the net power cost impacts associated with the outages required to either install the SCR systems or convert the units to natural gas.¹⁶³ For the SCR scenario, the Company modeled an outage in April and May of each

¹⁵⁷ Teply, Exh. No. CAT-40CT 8:11-19; Teply, TR. 519:5-520:25, 536:3-25.

¹⁵⁸ Teply, Exh. No. CAT-40CT 8:11-19; Twitchell, Exh. No. JBT-17C 1 (increasing SCR benefits [REDACTED]).

¹⁵⁹ Teply, Exh. No. CAT-40CT 7:10-8:10; Teply, Exh. No. CAT-41.

¹⁶⁰ Teply, TR. 517:2-14; Teply, Exh. No. CAT-40CT 7:10-8:10; Teply, Exh. No. CAT-41.

¹⁶¹ Teply, Exh. No. CAT-40CT 7:10-8:10; Teply, Exh. No. CAT-41.

¹⁶² Teply, TR. 521:21; Teply, Exh. No. CAT-40CT 5:22-6:1, 6:17-21, 8:22-9:1.

¹⁶³ See generally Link, Exh. No. RTL-11CT 22:8-26:17; Twitchell, Exh. No. JBT-15.

year, which corresponds to a time period when the outage would have a relatively small impact on net power costs.¹⁶⁴ In reality, the SCR installation outages were switched to fall, based economic and compliance considerations.¹⁶⁵ For the natural gas scenario, the same economic analysis confirmed that Units 3 and 4 should be run as coal units until the last possible date—meaning that the outages occur in January and February.¹⁶⁶

56 Staff contends the Company’s modeling created an inequity because it modeled the SCR outage during a low-demand period, while natural gas conversion was modeled during a high-demand period.¹⁶⁷ To account for this perceived inequity, Staff purports to calculate the replacement power costs included in the conversion scenario and then removes those costs so that there are no replacement power costs for the two months when the units are being converted.¹⁶⁸ Staff’s adjustment attempts to correct an inequity that does not exist.

57 Staff’s adjustment presumes that the outage window for each scenario should be the same.¹⁶⁹ This presumption is incorrect because the units would be dispatched differently depending on whether they are natural gas or coal units. The Company’s natural gas conversion scenario assumes that the conversion takes place once the units can no longer operate as coal units, so the replacement power costs are the costs that would be incurred to replace power that would otherwise have been generated by natural gas units.¹⁷⁰ Because the converted units would operate as peaker resources, they will not generally dispatch in January and February.¹⁷¹ Thus, converting the units in January and February results in virtually no replacement power costs

¹⁶⁴ Link, Exh. No. RTL-11CT 22:17-22.

¹⁶⁵ Link, Exh. No. RTL-11CT 23:3-7.

¹⁶⁶ Link, Exh. No. RTL-11CT 22:17-19; Teply, Exh. No. CAT-38CX.

¹⁶⁷ Twitchell, Exh. No. JBT-1CT 38:22-39:4.

¹⁶⁸ Twitchell, Exh. No. JBT-1CT 38:20-39:6; Twitchell, Exh. No. JBT-27CX.

¹⁶⁹ Twitchell, Exh. No. JBT-1CT 42:3-5.

¹⁷⁰ Link, Exh. No. RTL-11CT 25:18-26:11.

¹⁷¹ Link, Exh. No. RTL-11CT 25:18-26:11.

because the units would not otherwise be dispatched.¹⁷² If the conversion happens in the fall, as Staff claims it should, then the outage will remove coal units from service and the replacement power costs would be greater than zero because coal units would be dispatched during the fall.¹⁷³ Thus, the replacement power costs modeled for the natural gas conversion scenario are likely lower than the SCR scenario, not the other way around.

58 Staff’s adjustment also does not actually calculate the replacement power costs that would be incurred in January and February during the natural gas conversion outage. To calculate the replacement power costs that Staff removes from the natural gas conversion scenario, Staff compares the changes in system costs between a scenario where the units are operating as coal units (SCR scenario) and a scenario where the units are offline (natural gas conversion scenario).¹⁷⁴ But that is the wrong comparison. The correct comparison would determine the cost difference between a scenario where the units are operating as natural gas units and a scenario where the units are offline.¹⁷⁵ And again, because the converted units will not dispatch in January and February, the cost in each of these scenarios is effectively zero.

59 At hearing, Staff conceded that its adjustment was flawed and that its attempt to move the natural gas conversion outage to the fall “cannot be done” without running the SO Model.¹⁷⁶ But Staff never asked for access to the SO Model, nor did Staff ask the Company to re-run the model based on Staff’s preferred scenario.¹⁷⁷ In any event, an SO Model run would not have resolved the fundamental analytical flaws in Staff’s adjustment or produced the analysis Staff desires.

¹⁷² Link, Exh. No. RTL-11CT 25:18-26:11.

¹⁷³ Link, Exh. No. RTL-11CT 25:5-16.

¹⁷⁴ Twitchell, TR. 727:20-24.

¹⁷⁵ Link, Exh. No. RTL-11CT 25:18-26:11.

¹⁷⁶ Twitchell, TR. 730:9-15.

¹⁷⁷ See Twitchell, Exh. No. JBT-15. Staff asked if the Company “modeled replacement power costs during the work of gas conversion,” and the Company responded that it had. Staff then asked the Company to quantify the difference in replacement power costs for the SCR and gas conversion scenario, to which the Company replied that those costs cannot be isolated within the SO Model. Staff did not ask the Company to model this particular adjustment or otherwise inquire about the details of the Company’s replacement power cost modeling.

I. Sierra Club’s SCR Analysis Relies on Irrelevant Data, Unrealistic Assumptions, and Inconsistent Testimony.

1. Sierra Club’s 2013 IRP Comments Are Inconsistent with Its Position Here.

60 In August 2013, Sierra Club filed comments with the Commission relating to the Company’s 2013 IRP. Sierra Club stated that the 2013 IRP “represents large strides in the technical construction of an [IRP] with transparency in mechanisms and assumptions.”¹⁷⁸ The only reference to the Jim Bridger SCRs was Sierra Club’s assurance that the IRP was “broadly consistent” with the process used in the Wyoming CPCN proceeding “wherein most Company assumptions were open to intervenor examination.”¹⁷⁹ Sierra Club did not criticize or recommend non-acknowledgment of the Jim Bridger SCRs.

61 In January 2014, Sierra Club filed comments with the Oregon commission relating to the Company’s 2013 IRP. Sierra Club recommended that the Oregon commission not acknowledge the Jim Bridger SCRs for three reasons—total plant retirement would allow the Company to avoid transmission investments, the SCR analysis had understated carbon prices, and that the SCR decision was driven by a desire to keep the BCC mine open.¹⁸⁰ Sierra Club raised none of these issues in this case. More importantly, in neither Washington nor Oregon did Sierra Club argue that declining natural gas prices rendered the SCRs uneconomic. This fact is significant because Sierra Club’s comments were filed contemporaneous to the time it now claims that it was clear that declining natural gas prices made conversion a clearly superior option.¹⁸¹

2. Sierra Club’s Natural Gas Price Adjustment is Improper Hindsight Review.

62 Sierra Club testifies that “in principal” it agrees that the prudence review must examine

¹⁷⁸ Fisher, Exh. No. JIF-20CX 2.

¹⁷⁹ Fisher, Exh. No. JIF-20CX 2.

¹⁸⁰ Fisher, Exh. No. JIF-21CX 2-3.

¹⁸¹ Fisher, Exh. No. JIF-1CT 28:8-15, 29:9-30:9.

only information that was available to the Company before the issuing the FNTP on December 1, 2013.¹⁸² Sierra Club represents that its position is “[b]ased on a review of the data available to the Company at the time that it released its contractors to begin work on the SCRs.”¹⁸³ But this testimony cannot be squared with Sierra Club’s actual recommendations.

63 Sierra Club argues that the SCRs were uneconomic based on the forward gas prices included in the Company’s December 2013 OFPC.¹⁸⁴ Sierra Club acknowledges that this curve was not released until after the FNTP was issued, but claims that “it was based on information available before the FNTP and within a week and a half of executing the FNTP.”¹⁸⁵ This is untrue. The first six years of the curve were based on settled prices for December 30, 2013—a fact acknowledged by Sierra Club in its testimony.¹⁸⁶ At hearing, Sierra Club conceded that this information was not available to the Company on December 1.¹⁸⁷ The information that *was* available on December 1 were the consultant forecasts, discussed above, that had an average nominal levelized price of [REDACTED].¹⁸⁸ Sierra Club cannot reasonably claim that the possession of this information would have caused a reasonable utility to reverse course.

64 Sierra Club’s insistence on using the December 2013 OFPC is also undermined by its testimony in the Company’s Utah rate case shortly after the Company issued the FNTP. There Sierra Club argued that the September 2013 OFPC was the correct curve for determining whether to proceed with the SCRs.¹⁸⁹ At hearing, Dr. Fisher defended his prior reliance on the September 2013 OFPC, claiming that at the time he did not have the December 2013 OFPC and

¹⁸² Fisher, Exh. No. JIF-24CT 16:28.

¹⁸³ Fisher, Exh. No. JIF-1CT 3:15-18.

¹⁸⁴ Fisher, Exh. No. JIF-1CT 31:9-32:10.

¹⁸⁵ Fisher, Exh. No. JIF-1CT 29:4-6, Fisher, TR. 759:4-8.

¹⁸⁶ Fisher, Exh. No. JIF-11 1; Fisher, TR. 759:17-22.

¹⁸⁷ Fisher, TR. 760:11-14.

¹⁸⁸ Link, Exh. No. RTL-11CT 18:8-14.

¹⁸⁹ Fisher, Exh. No. JIF-22C22CX 9:3-12, 11:5-7.

did not know when the Company issued the FNTF.¹⁹⁰ But he also testifies that generally available data was sufficient to show that forward prices were plummeting after September, and admits that he knew the EPC contract was fully executed in December 2013.¹⁹¹

3. Sierra Club’s Original Coal Adjustment Relies on Irrelevant Post-Decision Data and Ignores Offsetting Changes in Capital Costs.

65 In its response testimony, Sierra Club contends that in fall 2013, Jim Bridger plant coal costs had increased by [REDACTED] for the four-unit scenario and [REDACTED] for the two-unit scenario.¹⁹² This analysis is seriously flawed. First, Sierra Club’s four-unit analysis is based on Jim Bridger plant fueling data taken from the Company’s 2015 IRP—data that was unavailable to the Company when it made its decision to proceed with the SCR investment.¹⁹³ On this point, Staff agrees that Sierra Club’s analysis is irrelevant.¹⁹⁴

66 Second, Sierra Club ignored changes in capital costs, which largely offset the identified cash cost increases.¹⁹⁵ To justify this omission, Sierra Club testified that its “initial analysis assumed that capital spending patterns had not changed markedly from January to October 2013.”¹⁹⁶ But in his response testimony, Dr. Fisher testifies that capital costs for his four-unit scenario decreased by [REDACTED].¹⁹⁷ Sierra Club also testifies that it did not consider capital costs because the Company “only provided evidence of capital spending on rebuttal, and provided previously undisclosed workbooks to support that claim.”¹⁹⁸ But Sierra Club confirmed that before filing its response testimony, it had all of the workbooks that it relied on in its

¹⁹⁰ Fisher, TR. 766:17-767:8.

¹⁹¹ Fisher, TR. 768:6-10; Fisher, Exh. No. JIF-1CT 29:9-30:9. And there was no reason Dr. Fisher could not have requested the December curve, as he acknowledged at hearing. Fisher, TR. 766:19-20.

¹⁹² Fisher, Exh. No. JIF-1CT 24:14-23.

¹⁹³ Fisher, Exh. No. JIF-1CT 17:14-21; Ralston, Exh. No. DR-1CT 9:13-10:6.

¹⁹⁴ Twitchell, Exh. No. JBT-28HCT 8:22-9:4.

¹⁹⁵ Ralston, Exh. No. DR-1CT 8:13; Fisher, Exh. No. JIF-1CT 22:13-23:11.

¹⁹⁶ Fisher, Exh. No. JIF-24CT 10:6-8.

¹⁹⁷ Fisher, Exh. No. JIF-1CT 23:15-24:12.

¹⁹⁸ Fisher, Exh. No. JIF-24CT 10:11-12.

supplemental testimony to determine capital costs.¹⁹⁹ And nowhere in Sierra Club’s response testimony did Dr. Fisher state that he did not rely on the October 2013 mine plan because it lacked capital costs—he testified that it was not a life-of-plant, long-term forecast and did not include third-party coal.²⁰⁰ Sierra Club had all the information it needed to account for capital costs, it simply chose not to do so.

4. Sierra Club’s Supplemental Coal Cost Analysis is Flawed.

67 In supplemental testimony, Sierra Club calculated a new adjustment that identified [REDACTED] in reduced BCC capital spending.²⁰¹ Instead of simply applying that as an offset to his previously calculated cash costs, Dr. Fisher creates an entirely new cash cost adjustment purportedly based on the Company’s October 2013 mine plan—the same mine plan that Sierra Club rejected for its original analysis as incomplete.²⁰² Using data out to 2035 from a plan that he acknowledges was not a “long-term fueling forecast,” Dr. Fisher increases his four-unit cash costs by [REDACTED] and decreases his two-unit costs by [REDACTED].²⁰³

68 The dramatic change in Sierra Club’s cash costs between its response and supplemental testimony undermines the veracity of Dr. Fisher’s analysis. Dr. Fisher testifies repeatedly that the mine plans he used in his response and supplemental testimony were consistent with one another and had nearly the same nominal levelized costs.²⁰⁴ This was how Dr. Fisher justifies using the 2015 IRP for his original adjustment. But at hearing, Dr. Fisher testified that he could not have simply offset his original adjustment by the [REDACTED] capital cost decrease because the two plans are “very different plans relative to each other” and cannot be compared.²⁰⁵ Dr. Fisher

¹⁹⁹ Fisher, Exh. No. JIF-27CCX 3.

²⁰⁰ Fisher, Exh. No. JIF-1CT 17:7-21.

²⁰¹ Fisher, Exh. No. JIF-24CT 15:8-16:1.

²⁰² Fisher, Exh. No. JIF-1CT 17:1-21.

²⁰³ Fisher, Exh. No. JIF-24CT 5:14-15, 16:21-25; Fisher, TR. 775:23-776:119; Fisher, Exh. No. JIF-27CCX 12.

²⁰⁴ Fisher, Exh. No. JIF-1CT 14:11-12, 17:14-21, 18:11-14; Fisher, Exh. No. JIF-24CT 5:14-17.

²⁰⁵ Fisher, TR. 774:15-21, 775:10-14.

cannot have it both ways—either the plans are comparable, in which case there should not have been the dramatic change in cash costs, or the plans are non-comparable, in which case Dr. Fisher’s response testimony was misleading.

69 Sierra Club further bolsters its conclusions by claiming consistency with Staff’s result, despite the use of different methodologies.²⁰⁶ But Staff’s “completely different methodology” included a mathematical error that, when corrected, creates an adjustment of only [REDACTED], which is fairly consistent with the Company’s testimony.²⁰⁷ By Dr. Fisher’s metric, this demonstrates the robustness of the Company’s analysis, not his own.

70 Sierra Club also claims to have remedied its prior reliance on irrelevant post-decision data by developing a coal adjustment based on the October 2013 mine plan.²⁰⁸ This adjustment still uses third-party pricing from July 2014, however.²⁰⁹ And Sierra Club indicated in discovery that it continues to support its original adjustment based on the 2015 IRP.²¹⁰

5. Sierra Club’s Two-Unit Scenarios Are Unrealistic and Ignore Material Costs.

71 Sierra Club developed three different two-unit scenarios. In each, the cash cost component is understated because it was taken directly from a four-unit scenario with no accounting for increased costs due to economies of scale in mine production quantities.²¹¹ The credibility of Sierra Club’s scenarios is also undermined by their overall results. Sierra Club contends that the “broad consistency” between its various two-unit scenarios demonstrate that costs for the two-unit scenario were decreasing in fall 2013.²¹² But Sierra Club’s original two-

²⁰⁶ Fisher, Exh. No. JIF-24CT 2:11-13, 3:7-13, 18:12-19.

²⁰⁷ Twitchell, Exh. No. JBT-41CCX. To be clear, the Company maintains that Staff’s analysis contains several other errors. But it is worth noting that using Staff’s methodology, inputs, and assumptions produces a 1.86 percent price change that is generally consistent with the Company’s analysis showing a roughly 2.5 percent change.

²⁰⁸ Fisher, Exh. No. JIF-24CT 16:26-17:1-7.

²⁰⁹ Fisher, Exh. No. JIF-24CT 13:1-2.

²¹⁰ Fisher, Exh. No. JIF-27CCX 1.

²¹¹ Fisher, Exh. No. JIF-1CT 21:15-18; Fisher, Exh. No. JIF-32CCX 3-8.

²¹² Fisher, Exh. No. JIF-24CT 17:1.

unit scenario had *increasing* costs of [REDACTED], while the supplemental scenarios had *decreasing* costs of [REDACTED].²¹³ A [REDACTED] difference is not consistent.

72 Regarding Sierra Club’s original two-unit scenario, at hearing Sierra Club appeared to repudiate that scenario, claiming that its supplemental scenarios were based on a “much more granular level of data.”²¹⁴ But Sierra Club acknowledged that the October 2013 mine plan on which these supplemental scenarios are based is incomplete and less granular.²¹⁵

73 In its supplemental testimony, Sierra Club develops two two-unit scenarios based on the October 2013 mine plan, and relies on Option A. This scenario assumes that the surface mine would be “effectively suspended” for six years, while the underground mine is run to depletion.²¹⁶ During that suspension, the Company would rely almost exclusively on the underground mine.²¹⁷ Based on what the Company knew in fall 2013, such heavy reliance on the underground mine would have been too risky because it would eliminate the Company’s ability to blend coal, which is essential for efficient plant operation, and create significant volume risk due to production variations.²¹⁸ [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

74 In addition, even assuming that Option A was a realistic option, the cost profile would be significantly higher. Sierra Club includes no costs to suspend the surface mine, maintain the

²¹³ Fisher, TR. 777:1-9.

²¹⁴ Fisher, TR. 778:5-9.

²¹⁵ Fisher, Exh. No. JIF-1CT 17:1-21.

²¹⁶ Fisher, Exh. No. JIF-24CT 13:10-14:2.

²¹⁷ Fisher, Exh. No. JIF-32CCX 3 (underground mine exclusively for five years and for 80 percent in sixth year)/

²¹⁸ Fisher, Exh. No. JIF-7 30; Ralston, Exh. No. DR-7CX7CCX 10:20-11:4; Fisher, Exh. No. JIF-6 1; Crane, Exh. No. CAC-13CCX 5.

²¹⁹ Crane, Exh. No. CAC-13CCX 5.

mine and its equipment during the suspension period, and then restart the mine after six years.²²⁰ Those costs would be substantial and are entirely ignored by Sierra Club. Sierra Club also assumes that under Option A, the Company would not have accelerated remediation of the surface mine because the mine would remain open until 2037.²²¹ But there is a very real risk that the Company would be required to begin remediation efforts at the surface mine as a result of a six-year suspension period.²²² Sierra Club's own analysis suggests that accelerated remediation costs would increase the costs of this option by [REDACTED].²²³

75 Even if accelerated depreciation is not triggered, the Company will be obligated to continue making reclamation trust contributions during the suspension period. Sierra Club included none of these costs in its analysis and did not make any other adjustments to account for the lack of reclamation contributions during the suspension period.²²⁴ At hearing, Dr. Fisher claimed that the reclamation costs were included in the capital costs.²²⁵ But he conceded that reclamation costs are cash costs, so they could not have been in his capital costs.²²⁶

76 Option B, Sierra Club's second two-unit scenario, assumes that both the surface and underground mine continue to operate through 2037.²²⁷ Option B also has fundamental analytical problems. Most notably, Sierra Club assumes that the same capital costs necessary to operate the underground mine until 2023 can operate the underground mine until 2037.²²⁸ This assumption is incorrect—even if the total volumes produced over the mine's life does not change, there will

²²⁰ Fisher, Exh. No. JIF-27CCX 4-6; Crane, Exh. No. CAC-13CCX 5.

²²¹ Fisher, Exh. No. JIF-24CT 8:7-10.

²²² Crane, Exh. No. CAC-13CCX 5.

²²³ Fisher, TR. 782:3-9.

²²⁴ Fisher, TR. 784:1-4.

²²⁵ Fisher, TR. 784:9-13 (reclamation costs "would have been incorporated into the ratioed [sic] capital costs").

²²⁶ Fisher, TR. 784:9-13.

²²⁷ Fisher, Exh. No. JIF-24CT 14:12-14.

²²⁸ Fisher, TR. 785:19-24; Fisher, Exh. No. JIF-24CT 14:17-19.

be additional capital costs to run the mine for 14 additional years.

6. The Company was Obligated to Install SCRs by Wyoming Regulators.

77 Sierra Club claims the Company had no SCR obligation until the EPA issued its final rule in January 2014.²²⁹ Sierra Club has unsuccessfully made this argument numerous times.²³⁰

Wyoming has been clear—its SCR requirement at Units 3 and 4 in 2015 and 2016 is independent of any action taken by EPA.²³¹ In early 2013, the Company specifically sought an extension of the compliance obligation based on EPA’s delay in issuing its final order.²³² Wyoming reaffirmed the Company’s compliance obligation and denied the extension.²³³ The Wyoming and Utah commissions both found that Wyoming’s requirements are independent of EPA.²³⁴

78 Moreover, as determined by the Wyoming and Utah commissions, a reasonable utility would not have delayed action pending EPA’s approval because delay would have harmed customers.²³⁵ EPA had never indicated that it was going to reject Wyoming’s determination related to Bridger Units 3 and 4.²³⁶ Despite Dr. Fisher’s previous insistence that EPA would “certainly” change the SCR requirement, EPA did not.²³⁷ Mr. Tepley testified that in his experience, EPA had never adopted a less stringent requirement than a state.²³⁸

79 At hearing, Sierra Club faulted the Company for complying with its administrative settlement with Wyoming regulators, arguing that it was not a court settlement and suggesting it was therefore unenforceable.²³⁹ Contrary to Sierra Club’s argument, it would have been

²²⁹ Fisher, Exh. No. JIF-1CT 8:1-3.

²³⁰ Fisher, Exh. No. JIF-28CX 4; Utah Pre-Approval Order at 9; Fisher, TR. 768:10-769:14.

²³¹ Tepley, Exh. No. CAT-25; Fisher, Exh. No. JIF-28CX 4.

²³² Tepley, Exh. No. CAT-26.

²³³ Tepley, Exh. No. CAT-25; Tepley Exh. No. CAT-14CT 17:18-20:19.

²³⁴ Fisher, Exh. No. JIF-28CX 4; Utah Pre-Approval Order at 9.

²³⁵ Fisher, Exh. No. JIF-28CX 4; Utah Pre-Approval Order at 9.

²³⁶ Fisher, Exh. No. JIF-29CX 2-4; Fisher, Exh. No. JIF-31CX 3:19-23.

²³⁷ Fisher, TR. 788:6-23.

²³⁸ Tepley, TR. 481:2-482:9, 482:16-23.

²³⁹ Tepley, TR. 494:13-495:7.

unreasonable for the Company to ignore its legal obligations under this settlement agreement because it was approved by a state regulator, not a court.

J. Both Staff and Sierra Club Ignore EPC Savings and Propose Problematic Remedies.

80 Staff's prudence analysis fails to account for EPC contract savings of over [REDACTED] on a revenue requirement basis. Staff never disputed these savings in its supplemental testimony. Instead, for the first time at hearing, Staff claimed that it was unable to independently verify that the Company was aware of these savings before issuing the FNTF.²⁴⁰ Mr. Teply's un rebutted testimony states that he was aware of these savings, and this fact can be confirmed by the Utah order approving the final EPC contract in December 2013, and by Dr. Fisher's testimony in the 2014 Utah rate case.²⁴¹ Staff admitted that it reviewed the records in both of these cases before filing response testimony.²⁴² Like Staff, Sierra Club also ignores the EPC contract cost savings. Unlike Staff, Sierra Club does not dispute these savings, having previously recognized them in a past proceeding. Sierra Club just refuses to account for them here.²⁴³

81 Finally, the remedies proposed by Staff and Sierra Club are incomplete. Staff proposes a remedy based on gas conversion costs, but fails to account for how such a remedy would be implemented in future power cost filings.²⁴⁴ Sierra Club's proposed disallowance is based on the Company's December 2014 OFPC, which clearly constitutes impermissible hindsight review.²⁴⁵

²⁴⁰ Twitchell, TR. 750:25-751:20.

²⁴¹ *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct SCRs on Jim Bridger Units 3 and 4*, Docket 12-035-92, Notice of Final Approved Projected Cost of Resource Decision at 3 (Dec. 30, 2013); Fisher, Exh. No. JIF-22CX 13:1-9; Fisher, TR. 769:20-771:24.

²⁴² Twitchell, Exh. No. JBT-1CT 61:8-62:4.

²⁴³ Fisher, TR. 770:18-21, 771:13-24.

²⁴⁴ Twitchell, Exh. No. JBT-1CT 54:3-15; Twitchell, Exh. No. JBT-24CX. Staff also challenged the prudence of two other capital projects at the Jim Bridger plant, based on Staff's conclusion that the projects would have been unnecessary if the units had been converted to gas. Twitchell, Exh. No. JBT-16. If the SCRs are prudent, as the Company contends, then Staff has not provided any basis to challenge the prudence of the remaining Jim Bridger investments. Teply, Exh. No. CAT-14CT 5:1-6.

²⁴⁵ Fisher, Exh. No. JIF-1CT 44:3-21. Unlike Staff, Sierra Club did not challenge the prudence of the remaining Jim Bridger plant capital projects. Teply, Exh. No. CAT-14CT 5:1-6.

Moreover, neither remedy considers the impact of the proposed disallowance on the Company. Although the Commission has rarely applied a prudence disallowance, it has been mindful of the need to “look ahead” and mitigate the impact on the utility’s “bottom line.”²⁴⁶

III. ACCELERATED DEPRECIATION

82 Pacific Power proposes to modify the depreciation lives for Jim Bridger Units 1-4 and for Colstrip 4, the coal-fueled generation plants serving Washington under the West Control Area Inter-Jurisdictional Allocation Methodology (WCA). These proposed changes in the end of the depreciable life for Jim Bridger, from 2037 to 2025, and for Colstrip 4, from 2046 to 2032, will return these plants to their pre-2008 depreciation lives and align the depreciation schedules for these plants between Washington and Oregon, the states that account for most of the west control area load.²⁴⁷ By shortening depreciable lives now, the Commission will minimize environmental compliance risks and costs for Washington, with only a modest impact to rates.

A. A Decade of Regulation Indicates a Trend Toward Limitations on Coal Generation.

83 Since 2006, both the state and federal governments have addressed concerns regarding climate change and air quality by adopting numerous laws and policies to regulate greenhouse gas emissions.²⁴⁸ In recent years, the intensity of these efforts has increased.²⁴⁹ In October 2015, the EPA published the final rule for the Clean Power Plan.²⁵⁰ In Washington, there are new executive and legislative efforts directed towards retiring coal plants, including Governor Jay

²⁴⁶ *WUTC v. Puget Sound Power & Light Co.*, Dockets UE-920499, *et al.*, Nineteenth Suppl. Order (Sept.27,1994) at 33.

²⁴⁷ Dalley, Exh. No. RBD-1T 10:13-11:6.

²⁴⁸ Dalley, Exh. No. RBD-1T 5:16-6:25.

²⁴⁹ Dalley, Exh. No. RBD-3T 8:13-9:22.

²⁵⁰ 80 Fed. Reg. 64,662 (Oct. 23, 2015). While the U.S. Supreme Court has granted a stay of this rule, implementation efforts continue in Washington pending the final outcome of the litigation. *Chamber of Commerce, et al. v. EPA, et al.*, Case No. 15A787, Order in Pending Case (Feb. 9, 2016). In addition, Washington recently proposed its own Clean Air rules to comprehensively regulate greenhouse gas emissions, WAC 173-442. Dep’t of Ecology, Proposed Rulemaking (May 31, 2016).

Inslee’s April 2014 Executive Order 14-04. This order directs the state to work with utilities to reduce greenhouse gas emissions from out-of-state coal-fueled facilities serving Washington customers, and asks the Commission to “actively assist and support the reduction in the use of coal-fired electricity, within the scope of its jurisdiction and authority.”²⁵¹ A similar effort in Oregon led to the recent passage of Senate Bill (SB) 1547, which excludes Pacific Power’s out-of-state coal plants from customer rates after 2030.²⁵²

84 In addition, Washington recently passed SB 6248, the purpose of which is largely analogous to the Company’s request here. SB 6248 recognized that there is no currently enacted statute or regulation mandating the closure of Colstrip Units 1 and 2.²⁵³ Yet, the legislation recognizes that it is good public policy to accelerate the collection of decommissioning costs to preemptively mitigate customer risk associated with potential early plant retirement.²⁵⁴ Pacific Power’s proposal for accelerated depreciation minimizes customer risk in a similar manner.

B. Accelerated Depreciation Minimizes Environmental Compliance Risk for Customers Without Significant Rate Impact.

85 Pacific Power’s accelerated depreciation proposal allows Washington customers to pay the remaining investment in Pacific Power’s west control area coal plants on an expedited basis, minimizing the risk that early retirement will result in stranded costs. The proposal protects customers from the rate shock they might otherwise experience if they are faced with paying for undepreciated investment in retired coal plants while at the same time paying for new alternative

²⁵¹ Governor Jay Inslee’s Executive Order 14-04 at 4 (Apr. 29, 2014).

²⁵² Or. Laws 2016, Ch. 28, § 1.

²⁵³ Dalley, Exh. No. RBD-3T 9:3-22.

²⁵⁴ Dalley, Exh. No. RBD-3T 9:18-22. SB 6248 mitigates risk by allowing PSE to start collecting additional decommissioning and reclamation costs. PSE may collect these funds even though there is no definitive plan to retire Colstrip 1 and 2 by a date certain. Pacific Power’s proposal is different in its mechanism but motivated by the same concerns.

sources of generation.²⁵⁵ Aligning the end-of-lives for these plants with those adopted in Oregon will provide the Company with greater flexibility in developing least-cost strategies for environmental compliance that are acceptable to customers in both states.²⁵⁶ Pacific Power’s proposal that the Commission take action early—before retirement decisions are imminent—significantly reduces the economic impact on customers.

86 The benefits of accelerating depreciation now are illustrated by considering Pacific Power’s December 31, 2022, and December 31, 2021, Regional Haze deadlines for Jim Bridger Units 1 and 2, respectively.²⁵⁷ The Company’s economic analysis of its compliance options will not be completed for several years. If this analysis demonstrates that early retirement is the most cost-effective option, customers will have a very short time to pay off the remaining plant balances before retirement. If a large balance remains, customers will face steep rate increases to collect that investment, while at the same time paying for new replacement generation. Unless depreciation is accelerated now, concerns about rate shock could undercut customer support for an early retirement option, even if this was otherwise the most economic option. And if Washington and Oregon customers’ interests are not aligned in this respect, the Company’s options could be further limited.

87 The Commission has authority to adjust depreciable lives to address concerns about future regulatory requirements. RCW 80.04.350 grants the Commission authority to “fix the proper and adequate rates of depreciation or retirement” of utility property. This statute “allows broad discretion to the Commission to set depreciation rates and methods.”²⁵⁸ A major

²⁵⁵ Dalley, TR. 223:23-224:18.

²⁵⁶ Oregon and Washington have a long history of collaboration to encourage the reduction of greenhouse gasses. *See* Dalley, Exh. No. RBD-3T 10:18-11:6.

²⁵⁷ Fisher, Exh. No. JIF-30CX 3.

²⁵⁸ *US West Commc’ns, Inc. v. WUTC*, 134 Wn.2d 48, 59 (1997); Dalley, TR. 198:9-199:2.

component in the calculation of depreciation expense is the “economically useful life” of the plant, which the Commission has recognized is “necessarily [an] estimate[.]” and which the Washington Supreme Court has observed is “essentially [a] matter[.] of opinion.”²⁵⁹

88 There is precedent for the Company’s proposal in its 2013 depreciation study, where the Company explained that that it was explicitly declining to extend the depreciation lives of its steam generating units because of “the regulatory and statutory uncertainty regarding the period in which steam generating facilities will be allowed to operate[.]”²⁶⁰ The Commission adopted those unchanged depreciation rates as proposed.²⁶¹ It is similarly appropriate for the Commission to shorten the lives of the Jim Bridger plant and Colstrip 4 in this case.

89 Finally, RCW 80.04.350 states that in fixing depreciation rates the “Commission may consider the rate and the amount therefore charged by the company for depreciation or retirement.” The Commission’s discretion to set depreciation rates includes authorization to consider the rate impact on customers including actions to prevent rate shock—which is a primary goal of the Company’s proposal.

C. Several Parties Support Accelerated Depreciation, and No Party Has Raised Any Meaningful Impediment.

90 Boise White Paper, LLC (Boise) agrees that the benefits of accelerated depreciation exceed the costs, relying on economic factors including “historically low” gas prices and “oversupply in power markets.”²⁶² NW Energy Coalition (NWEC) supports accelerated

²⁵⁹ *In re US West Commc’ns, Inc.*, Docket UT-940641, 4th Suppl. Order, 1995 WL 422151 at *2-3 (May 26, 1995); *US West Commc’ns, Inc. v. WUTC*, 134 Wn.2d 48, 68 (1997) (quoting *Lindheimer v. Ill. Bell Tel. Co.*, 292 U.S. 151, 169 (1934)) (“the calculations of depreciation expenses are mathematical but the predictions underlying them are essentially matters of opinion”).

²⁶⁰ Dalley, Exh. No. RBD-8CX 9:1-5.

²⁶¹ *In re Pac. Power’s Petition for an Accounting Order Authorizing a Revision to Depreciation Rates*, Docket UE-130052, Order 01 (Dec. 27, 2013).

²⁶² Mullins, Exh. No. BGM-1CT 3:17-19.

depreciation because it is consistent with Washington’s policies and statutes aimed at reducing greenhouse gas emissions.²⁶³ Sierra Club supports the proposal because it will remove barriers to early plant retirement, prevent the need for stranded cost recovery from customers no longer served by plant, and mitigate potential rate shock from early retirement.²⁶⁴

91 Staff and Public Counsel oppose Pacific Power’s depreciation proposal, arguing that the Company has not committed to actually shutting down the Jim Bridger plant and Colstrip 4 at the end of their new depreciable lives and that changing the depreciable lives will not restrict the operation of the plants.²⁶⁵ These arguments erroneously suggest that depreciation rates must be based on the demonstrated life of an asset, and that the Commission cannot shorten an asset’s depreciable life until the Company can provide a date certain for closure. This position conflicts with Washington law, which allows the Commission to consider rate shock and policy matters in fixing depreciation schedules.

92 Public Counsel also argues that accelerated depreciation could result in intergenerational inequity if the plants are fully depreciated while they are still providing service to Washington customers.²⁶⁶ The Company believes that it is now more likely than not that the Jim Bridger plant and Colstrip 4 will close before the end of their current depreciable lives, so there is a greater risk of intergenerational inequity associated with maintaining current schedules than with accelerating them.²⁶⁷ As noted by Sierra Club, accelerated depreciation minimizes “the risk of inter-temporal cost shifting between current ratepayers who are continuing to receive power from the plant, and future ratepayers who may otherwise be required to pay off” stranded assets.²⁶⁸

²⁶³ Cavanagh, Exh. No. RC-1T 10:11-11:13.

²⁶⁴ Fisher, Exh. No. JIF-1CT 34:22-35:18.

²⁶⁵ Huang, Exh. No. JH-1T 10:12-19; Ramas, Exh. No. DMR-1T Revised (04/01/16) 22:7-24.

²⁶⁶ Ramas, Exh. No. DMR-1T Revised (04/01/16) 21:8-19.

²⁶⁷ Dalley, Exh. No. RBD-3T 13:6-14.

²⁶⁸ Fisher, Exh. No. JIF-1CT 35:7-11.

93 Staff and Public Counsel also claim it is inappropriate to approve new depreciation rates without an updated depreciation study.²⁶⁹ The depreciation lives proposed here are identical to what the Commission approved in the Company's 2007 depreciation study, so there is a reasonable basis to reinstate them here. As discussed above, the Commission has authority to make a limited adjustment to depreciation rates based on policy concerns, with or without a new depreciation study. Staff and Public Counsel have not explained how a new depreciation study would inform the Commission's decision on the Company's proposal.

94 The Company will be filing its next depreciation study in 2018.²⁷⁰ By that time, the Company's regulatory requirements applicable to its coal plants should be clearer, and the Commission may reconsider the depreciable lives it adopts in this case. In the interim, the Commission can protect customers from the risks that attend an uncertain future by adopting the Company's proposal in this case.

95 Finally, Public Counsel proposed an alternative under which depreciation rates would remain unchanged, but the Company would create a regulatory liability and collect an early retirement expense that could be used to offset stranded costs if a plant is retired early.²⁷¹ At hearing, Public Counsel specifically mentioned Utah legislation requiring this approach.²⁷² Public Counsel's proposal adds unnecessary burdens with no incremental benefit. The Company is already tracking and reporting accelerated depreciation expense in Oregon, and under its proposal would do the same in Washington.²⁷³ The result is complete transparency for the

²⁶⁹ Huang, Exh. No. JH-1T 11:11-13; Ramas, Exh. No. DMR-1T Revised (04/01/16) 21:20-22:6.

²⁷⁰ Dalley, TR. 163:3-10.

²⁷¹ Ramas, Exh. No. DMR-1T Revised (04/01/16) 27:3-28:20. At hearing there was discussion regarding the relationship between Public Counsel's alternative proposal and Staff's recommendation that the Company file annual reports. Ramas, TR. 379:4-381:6; Ball, Exh. No. JLB-1T 58:25-59:6. The Company does not object to annual reports but, to be clear, the issue of accelerated depreciation is distinct from the sufficiency of the accruals.

²⁷² Dalley, TR. 167:1-168:5.

²⁷³ Dalley, TR. 214:24-216:21.

Commission and customers, which would not be enhanced under Public Counsel’s framework.²⁷⁴

96 Although Boise supports accelerated depreciation, Boise proposes that if approved, only a portion of the SCR investment should be included in rates, based on the proposed 2025 depreciable life for Jim Bridger Units 3 and 4.²⁷⁵ This proposal improperly assumes that the Jim Bridger plant will no longer serve Washington customers after 2025, which is not a part of the Company’s proposal. If the plant continues to serve customers, it should remain in rates.²⁷⁶

IV. LIMITED-ISSUE FILING, RATE PLAN, AND END-OF-PERIOD RATE BASE

A. Pacific Power’s Limited-Issue Filing and Rate Plan, with End-of-Period Rate Base, Will Help Prevent Annual Rate Case Filings.

97 Over the last several years, the Commission has focused on breaking the cycle of annual general rate case filings by encouraging utilities, including Pacific Power, to use alternative ratemaking tools to address regulatory lag and persistent under-recovery.²⁷⁷ To effectuate this policy, the Commission has approved limited-issue rate cases, multi-year rate plans, end-of-period (EOP) rate base, decoupling mechanisms, and attrition adjustments.²⁷⁸ The Commission has not required utilities to show extraordinary circumstances to justify such proposals.²⁷⁹

98 The Company built this filing around these alternative ratemaking tools, seeking a way to obviate annual rate case filings. The case is a limited-issue filing for an initial rate increase under

²⁷⁴ Dalley, Exh. No. RBD-3T 14:16-17:6. The Utah model is also inapplicable because it mandates a complex solution for early retirement that operates as a trade-off for how demand-side management costs are recovered. Dalley TR 207:23-208:13.

²⁷⁵ Mullins, Exh. No. BGM-1CT 13:6-14, 38:12-19.

²⁷⁶ Dalley, Exh. No. RBD-3T 17:11-18:2.

²⁷⁷ See e.g. *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697, et al., Order 07 (June 25, 2013) (approving an expedited rate filing, EOP rate base, rate plan, and decoupling proposal as “innovative ratemaking mechanisms that fulfill the Commission’s policy goal of breaking the recent pattern of almost continuous rate cases.”).

²⁷⁸ *WUTC v. Avista Corp.*, Dockets UE-120436, et al., Order 09/14 ¶1-2 (Dec. 26, 2012) (multi-year rate plan); Pacific Power’s 2013 GRC Order ¶184 (EOP rate base); *WUTC v. Avista Corp.*, Dockets UE-140188, et al., Order 05 ¶28 (Nov. 25, 2014) (decoupling); *WUTC v. Avista Corp.*, Dockets UE-150204, et al., Order 05 ¶135 (Jan. 6, 2016) (attrition adjustment).

²⁷⁹ *WUTC v. Avista Corp.*, Dockets UE-150204, et al., Order 05 ¶110 (Jan. 6, 2016).

three percent (*i.e.*, 2.69 percent), with a rate plan seeking a second-year rate increase also under three percent (*i.e.*, 2.99 percent), EOP rate base, and a decoupling mechanism.²⁸⁰ The first-year increase is based on a modified Commission Basis Report with a test year ending June 30, 2015, and follows Staff's previous recommendations on the design of a limited-issue rate case.²⁸¹ The pro forma adjustments are limited to accelerated depreciation, SCR upgrades at Jim Bridger Unit 3, EOP rate base, and the Idaho Power Asset Exchange (Exchange).²⁸²

99 The rate plan's second-year increase is based on discrete capital investments, including SCRs at Jim Bridger Unit 4 and the expiration of production tax credits.²⁸³ The major capital additions are either in-service or will soon be in-service.²⁸⁴ The Company will submit attestations regarding the in-service dates and final costs of those projects to ensure that—before rates change—the adjustments will be fully known and measurable and the resources will be used and useful.²⁸⁵ The rate plan is linked to a stay-out provision that avoids another rate case filing for a rate change effective before June 1, 2018.²⁸⁶

100 Pacific Power's historical pattern of under-earning demonstrates that the proposed rate plan with EOP rate base is necessary to break the Company's near-annual rate case filings. Between 2006 and 2014, the Company earned less than its authorized return on equity (ROE) in Washington by an average of more than five percent.²⁸⁷ For nine consecutive years, the

²⁸⁰ Dalley, Exh. No. RBD-1T 2:4-20.

²⁸¹ Dalley, Exh. No. RBD-1T 6:26-7:2; Dalley, Exh. No. RBD-6CX.

²⁸² Dalley, Exh. No. RBD-1T 7:2-10; McCoy, Exh. No. SEM-1T 9:21-10:21, 11:8-12:21. The Company's limited rate filing did not propose changes to its cost of capital or net power costs. Dalley, Exh. No. RBD-1T 11:15-19.

²⁸³ Dalley, Exh. No. RBD-1T 16:11-17:14. The second year rate base updates are calculated using an average of monthly averages using an anticipated effective date of July 1, 2017. McCoy, Exh. No. SEM-6T 26:3-5.

²⁸⁴ Dalley, TR. 170:20-171:3 (EMS/SCADA project in service; Union Gap in service by end of May 2016; Bridger Unit 4 SCRs in service by November 2016).

²⁸⁵ Dalley, Exh. No. RBD-1T 17:18-20. The attestation process addresses Boise's argument that the second-year rate increase is not based on the known and measurable standard and Boise's proposed forecast error adjustment.

Mullins, Exh. No. BGM-1CT 7:13-8:13, 41:1-42:5.

²⁸⁶ Dalley, Exh. No. RBD-3T 18:12-14.

²⁸⁷ Dalley, Exh. No. RBD-1T 9 Table 1.

Company has not earned its authorized rate of return in Washington, despite aggressively managing its costs and filing eight general rate cases since 2005.²⁸⁸ The Commission previously recognized such a pattern of under-earning as attrition, which supports adoption of a rate plan to allow the Company an opportunity to recover its costs to serve without annual filings.²⁸⁹

101 EOP rate base is a key component of both years of Pacific Power’s rate plan. The Commission has required a demonstration of one of four conditions to justify EOP rate base: (a) abnormal growth in plant; (b) inflation and/or attrition; (c) to reduce regulatory lag; (d) failure of a utility to earn its authorized rate of return over an historical period.²⁹⁰ In this case, the Company has shown that EOP rate base will reduce regulatory lag and more accurately reflect the level of rate base during the rate-effective period, which will extend at least until June 2018.²⁹¹ It is also undisputed that the Company has not earned its authorized return for an extended historical period, despite the Company’s well-documented efforts to control costs. Finally, at hearing, the Company testified that the more than \$300 million capital additions in this case could be considered abnormal or extraordinary growth.²⁹²

102 In its order in the Company’s 2014 rate case—which did not involve a rate plan—the Commission found that the Company did not meet the standard for EOP rate base.²⁹³ The Commission did not foreclose the possibility of EOP rate base in the future “if there is an adequate showing that it promises the results we expect,” *i.e.*, that it will break the cycle of annual rate cases.²⁹⁴ While the Commission found that the Company’s historical under-earning

²⁸⁸ Dalley, Exh. No. RBD-1T 9:1-5.

²⁸⁹ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697, *et al.*, Order 07 ¶¶147-149 (June 25, 2013).

²⁹⁰ *WUTC v. Pac. Power & Light Co.*, Dockets UE-140762, *et al.*, Order 08 ¶145 (Mar. 25, 2015) (hereinafter, “Pacific Power’s 2014 GRC Order”).

²⁹¹ Dalley, TR. 172:22-173:15.

²⁹² Dalley, TR. 172:1-11.

²⁹³ Pacific Power’s 2014 GRC Order ¶151.

²⁹⁴ *Id.*

may not predict its future under earnings, it has also held the opposite in a case (like this one) that involved a rate plan.²⁹⁵ Looking to historical under-earnings to support EOP rate base in the rate plan context is consistent with the Commission’s usual practice of using normalized historical data to forecast components of future rates.²⁹⁶

103 The Company’s EOP proposal here also minimizes mismatches between costs and revenues.²⁹⁷ The Company has reflected EOP revenues, along with rate base, so that the rate increase resulting from the last rate case is reflected as if it were in place during the entire test period. This approach ensures that costs and revenues are appropriately matched and that the use of EOP rate base upholds the matching principle.

104 Boise argues that the Company has not consistently applied EOP rate base because the pro forma capital additions are not based on EOP balances.²⁹⁸ But Boise’s proposal to use EOP balances for pro forma adjustments would mean that rates would be set using rate base balances at the *end* of the rate year—not the levels in effect *during* the rate year.²⁹⁹

105 In key respects, Staff supports the Company’s alternative ratemaking proposals:

- Staff supports the rate plan as a way to end the nearly annual rate case filings and to address regulatory lag.³⁰⁰
- Staff agrees that the “proposed rate plan is a well-designed stay-out period with discrete adjustments” that is “in step with prior Commission orders.”³⁰¹
- Staff notes that a key feature of a rate plan is that in exchange for a stay-out period, the Company “either receives a series of pre-determined rate adjustments or some other type of incentive for agreeing to the stay-out period.”³⁰² This benefits customers because “[b]y providing a company with additional revenue, either

²⁹⁵ *Id.*; *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697, *et al.*, Order 07 ¶¶47 n. 59, 48 (June 25, 2013).

²⁹⁶ *See e.g.*, Pacific Power’s 2014 GRC Order ¶52 (Mar. 25, 2015) (using historical data to normalize rate year expenses); *WUTC v. Pac. Power & Light Co.*, Docket UE-100749, Order 06 ¶135 (Mar. 25, 2011) (using historical data to predict future net power costs).

²⁹⁷ Pacific Power’s 2013 GRC Order ¶185.

²⁹⁸ Mullins, Exh. No. BGM-1CT 21:3-22:7.

²⁹⁹ Pacific Power & Light Co. Response to ALJ Bench Request No. 8.

³⁰⁰ Ball, Exh. No. JLB-1T 16:13-17:14, 23:1-15.

³⁰¹ Ball, Exh. No. JLB-1T 3:11-12, 7:8-9.

³⁰² Ball, Exh. No. JLB-1T 18:4-7.

through automatic adjustments, additional return on equity, or other mechanisms, the company is directly incentivized to control its costs in order to achieve maximum possible earnings.”³⁰³

- Staff supports the Company’s proposed use of attestations to verify both the in-service date and the final costs for each pro forma capital addition.³⁰⁴
- Staff supports the use of EOP rate base in the context of a two-year rate plan because it “more appropriately align[s] rate base balances with the rate effective period in both year one and year two of the rate plan.”³⁰⁵

106 As a whole, the Company’s proposals benefit Washington customers by limiting annual rate increases to less than three percent, extending the time between general rate cases and making rates more predictable, prudently responding to current and future environmental mandates, removing disincentives for energy efficiency, requiring additional reporting and earnings sharing, and increasing Low Income Bill Assistance (LIBA) funding in this and future cases.³⁰⁶ The filing also provides the Company needed cost recovery, thereby enabling investments necessary to provide safe and reliable utility service.³⁰⁷

B. Public Counsel’s and Boise’s Objections to the Alternative Ratemaking Proposals are Out-of-Step with Commission Policy.

107 Public Counsel and Boise oppose the rate plan and EOP rate base because the Company has not conducted a formal attrition study, which they argue is a precondition to the use of these regulatory tools.³⁰⁸ Staff agrees that the Company has not formally established earnings attrition, but concludes that a finding of attrition is unnecessary for the rate plan or EOP rate base.³⁰⁹

108 The Commission has defined attrition “broadly to mean any situation in which a rate-regulated business fails to achieve its allowed earnings.”³¹⁰ The Company relies upon this

³⁰³ Ball, Exh. No. JLB-1T 18:9-12.

³⁰⁴ Ball, Exh. No. JLB-1T 24:17-25:17.

³⁰⁵ Huang, Exh. No. JH-1T 4:6-9.

³⁰⁶ Dalley, Exh. No. RBD-3T 5:2-8.

³⁰⁷ Dalley, Exh. No. RBD-3T 5:8-10.

³⁰⁸ Ramas, Exh. No. DMR-1T Revised (04/01/16) 10:3-11; Mullins, Exh. No. BGM-1CT 6:15-17.

³⁰⁹ Ball, Exh. No. JLB-1T 22:12-24:3.

³¹⁰ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697, *et al.*, Order 07 ¶¶22, n.23, 142 (June 25, 2013); *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048, *et al.*, Order 08 ¶484, n.658 (May 7, 2012).

definition of attrition (*i.e.*, a pattern of historical under earning) to show that the rate plan and EOP rate base are needed alternatives to annual rate case filings. The Company is not proposing a formal attrition adjustment that relies on trending analysis or escalation factors to establish the Company's second-year rate increase. Instead, the Company's second-year rate increase is based on limited, discrete adjustments.

109 Public Counsel contends that the Company's costs are actually decreasing and therefore the Company is not experiencing earnings attrition.³¹¹ The fact that the Company aggressively reduces its costs and is still unable to earn its authorized return shows that many cost drivers are outside of its control.³¹² Public Counsel's argument actually demonstrates that despite its efficiency savings, the Company's authorized rates remain insufficient. Notably, Public Counsel made largely the same argument in Avista's 2015 rate case, which the Commission rejected.³¹³

110 Relying on similar arguments, Public Counsel and Boise also argue that Pacific Power did not satisfy the Commission's criteria for approval of EOP rate base.³¹⁴ While Public Counsel argues that historical under-earning is no basis for EOP rate base, it took the opposite position in Avista's 2015 rate case. In that case, Public Counsel supported the use of EOP rate base for Avista's gas operations, observing the EOP rate base is appropriate when a utility can "demonstrate that it is experiencing attrition *or that it has been unable to achieve its authorized rate of return* under the more traditional historic test year approach."³¹⁵ Public Counsel testified that Avista presented "compelling evidence" that it had "consistently earned below its authorized rate of return for its natural gas operations," which consisted of Avista's annual rates of return.³¹⁶

³¹¹ Exh. No. DMR-1T Revised (04/01/16) 47:1-49:4.

³¹² Dalley, Exh. No. RBD-3T 25:5-9.

³¹³ *WUTC v. Avista Corp.*, Dockets UE-150204, *et al.*, Order 05 ¶135 (Jan. 6, 2016).

³¹⁴ Ramas, Exh. No. DMR-1T Revised (04/01/16) 10:3-11; Mullins, Exh. No. BGM-1CT 22:8-23:3.

³¹⁵ Dalley, Exh. No. RBD-3T 31:8-13 (emphasis added).

³¹⁶ Dalley, Exh. No. RBD-3T 31:14-21.

V. COST OF CAPITAL

111 Because this is a limited-issue filing, the Company does not seek a change to its current cost of capital, which the Commission approved in March 2015 in the Company's 2014 rate case.³¹⁷ Mr. Kurt Strunk testifies that maintenance of a 7.30 percent rate of return and a 9.5 percent ROE is reasonable because today's capital markets are similar, if not higher, than they were at that time.³¹⁸ Mr. Bruce Williams similarly testifies that the Company's debt costs are similar (slightly higher) than its approved cost of debt.³¹⁹

112 The results of Mr. Strunk's discounted cash flow, risk premium, and comparable earnings models indicate that a 9.5 percent ROE falls well within the range of reasonableness.³²⁰ Certain models are higher in this case and some are lower, supporting Mr. Strunk's recommendation to maintain the status quo.³²¹ Mr. Strunk's recommendation is informed by continuing anomalous capital market conditions created by central bank interventions, and his assessment that the Company's alternative rate making proposals present new risks despite the potential benefits.³²²

113 A 9.5 percent ROE is conservative, given that it is at the bottom of the range of approved ROEs for vertically integrated utilities—since November 2013, only one has received an authorized ROE less than 9.5 percent.³²³ The average ROE for 2015 was 9.85 percent, 35 basis points higher than the Company's. The Company's current ROE is the same as Avista's, which the Commission approved earlier this year, and 30 basis points lower than the ROE in Puget Sound Energy's (PSE) rate plan, which was extended on March 17, 2016.³²⁴

³¹⁷ Pacific Power's 2014 GRC Order ¶183.

³¹⁸ Strunk, Exh. No. KGS-1T 5:1-6:4.

³¹⁹ Williams, Exh. No. BNW-1T 2:14-16, 4:18-19.

³²⁰ Strunk, Exh. No. KGS-19T 13:10-20.

³²¹ Strunk, Exh. No. KGS-20; Strunk, Exh. No. KGS-1T 5:16-20.

³²² Strunk, Exh. No. KGS-1T 11:13-14:12, 16:14-19:2.

³²³ Strunk, Exh. No. KGS-3.

³²⁴ Strunk, Exh. No. KGS-20; Strunk, Exh. No. KGS-19T 14:11-21.

114 The Company’s proposed rate plan and decoupling mechanism further support a 9.5 percent ROE. As Staff witness Jason Ball testifies, the rate plan creates increased risk that actually supports an ROE premium.³²⁵ And the Commission has previously found that a rate plan, earnings test, and increased conservation targets (all of which are proposed here) support an ROE above the mid-point of the range of reasonable returns.³²⁶

115 Staff recommends a 25-basis-point reduction in the Company’s ROE, based on Mr. David C. Parcell’s conclusion that equity costs decreased since the Company’s last case.³²⁷ The evidence does not support that conclusion. First, Mr. Parcell’s overall recommendation *increased* 25 basis points over the last case, contradicting his position that ROEs decreased.³²⁸ Second, interest rates increased.³²⁹ In the last case, Mr. Parcell testified “logic would indicate” that if interest rates are higher today, the Company’s ROE is higher too.³³⁰ Not only are interest rates higher, but the Company’s debt cost and bond spreads are also higher.³³¹

116 Third, Mr. Parcell recommends a de facto decoupling adjustment by capping the ROE at 9.25 percent, the mid-point of the reasonable range.³³² But in the Company’s 2014 rate case, Mr. Parcell testified that the impact of decoupling is built into the proxy group and that decoupling is “not a factor that I would be comfortable either adding to or subtracting from” a recommended ROE.³³³ Similarly, in PSE’s remand proceeding, Mr. Parcell testified against a decoupling adjustment to ROE.³³⁴ The Commission has also found that the impact of decoupling

³²⁵ Ball, Exh. No. JLB-1T 18:4-14, n.13; Strunk, Exh. No. KGS-19T 16:14-17:7.

³²⁶ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697, *et al.*, Order 15 ¶¶157, 161-162 (June 29, 2015); Strunk, Exh. No. KGS-19T 16:3-17:7.

³²⁷ Parcell, Exh. No. DCP-1T 4:18-19, 14:15-18.

³²⁸ Strunk, Exh. No. KGS-19T 2:20-22.

³²⁹ Parcell, Exh. No. DCP-4 4 (Aa bonds were 3.94% in Feb. 2016 and 3.67% in Mar. 2015).

³³⁰ Parcell, Exh. No. DCP-16CX 3:6-12 (testifying ROEs track interest rates).

³³¹ Strunk, Exh. No. KGS-19T 5:3-8; Strunk, Exh. No. KGS-33; Parcell, Exh. No. DCP-1T 3:6.

³³² Parcell, Exh. No. DCP-1T 36:7-37:2.

³³³ Parcell, Exh. No. DCP-16CX 5:3-10.

³³⁴ Parcell, Exh. No. DCP-15CX 2:22-3:7.

is accounted for in the proxy group and therefore an ROE anywhere within the reasonable range will result in just and reasonable rates.³³⁵

117 Fourth, Mr. Parcell testifies that the Company’s proposed rate plan reduces risk.³³⁶ This is contradicted by Mr. Ball, who testifies that the rate plan *increases* risk—a conclusion that accords with Commission’s precedent.³³⁷ Fifth, Mr. Parcell’s analysis includes data errors and introduces unreasonable subjective adjustments to his results that narrow his range and depress his overall recommendation.³³⁸ In summary, the evidence supports a decision to maintain the Company’s current cost of capital, not to reduce it as Staff proposes.

VI. IDAHO POWER ASSET EXCHANGE

118 In 2015, the Company filed a request for approval for the exchange of certain transmission assets with Idaho Power Company (Idaho Power). In September, Staff identified customer benefits of the Exchange, including an increase in the Company’s ability to serve loads in the west control area in certain outage situations, improved administrative efficiency from the replacement of legacy agreements with transparent Open Access Transmission Tariff (OATT)-based transactions, improved prospects for cost sharing with Idaho Power on future projects and an increase in Pacific Power’s ownership in the transmission lines it uses to serve the west control area, thereby reducing the need for wheeling on Idaho Power lines.³³⁹ Staff compared these benefits to Washington customers with the expected cost of \$575,000, and concluded that the “minor rate increase is balanced by potential benefits.”³⁴⁰ Consistent with Staff’s

³³⁵ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-121697, *et al.*, Order 15 ¶156 (June 29, 2015); *see also* Strunk, Exh. No. KGS-19T 15:15-16:2.

³³⁶ Parcell, Exh. No. DCP-1T 36:18-19.

³³⁷ Ball, Exh. No. JLB-1T 18:4-14, n.13; Strunk, Exh. No. KGS-19T 16:14-17:7.

³³⁸ Strunk, Exh. No. KGS-19T 8:4-9:9.

³³⁹ Ball, Exh. No. JLB-7CX 6-7.

³⁴⁰ Ball, Exh. No. JLB-7CX 3, 7.

recommendation, the Commission approved the application.³⁴¹ The Company has completed the Exchange and updated its rate base in this case to reflect the assets now serving the west control area.³⁴²

119 Customers have already realized the benefits identified by the Commission. The Company now has firm point-to-point transmission rights under the OATT, providing added reliability in moving resources across Idaho Power's system to serve Washington customers.³⁴³ Pacific Power's ownership of an additional line from the Jim Bridger plant means that the Company now has three paths from the plant to the west control area, which will allow service to Washington customers even when two lines are down.³⁴⁴ The Company has verified that the revenue requirement impact of the Exchange is \$552,401, which is less than the estimated impact assumed by the Commission when it approved the transaction.³⁴⁵

120 Staff opposes Pacific Power's request, arguing that the Company failed to demonstrate that the benefits of the Exchange are commensurate with the costs.³⁴⁶ Staff claims that because the Company did not update power costs in this case, customers are not receiving the benefits that flow from increased flexibility and wheeling, or the benefit of dynamic overlay.³⁴⁷ Staff's position disregards the undisputed fact that customers are receiving reliability benefits now, which should be matched in rates by the associated costs.

121 In addition, when asked to confirm at hearing that power cost benefits of the Exchange

³⁴¹ *In re Pac. Power's Petition for an Order Approving the Exch. of Certain Transmission Assets with Idaho Power Co.*, Docket UE-144136, Order 01 ¶9 (Sep. 24, 2015).

³⁴² McCoy, Exh. No. SEM-1T 9:11-11:6.

³⁴³ Vail, Exh. No. RAV-3T 5:15-6:3; Ball, TR. 338:9-13.

³⁴⁴ Vail, TR. 287:10-289:6, 288:23-24 ("Yes, there have been times when both of those facilities [Bridger to Populus to Borah lines] have been down at the same time."); Vail, Exh. No. RAV-3T 5:1-9.

³⁴⁵ Pacific Power & Light Co. Response to Bench Request No. 3 (\$350,838 (Exchanged Assets) + \$201,563 (Reassigned Assets) = \$552,401).

³⁴⁶ Ball, Exh. No. JLB-1T 70:19-71:11.

³⁴⁷ Staff does not support a change to net power costs in this proceeding. Ball, Exh. No. JLB-1T 71:19-20.

will flow to customers through the Company's power cost adjustment mechanism (PCAM), Staff argued that overall benefits would need to exceed the dead bands for benefits to get to customers, and that they would be shared.³⁴⁸ The PCAM is designed to pass through all variations in power costs. PCAM surcharges or credits are the aggregate total for overall costs and reflect the total benefits and costs of all power cost transactions.³⁴⁹ It is contrary to the intent of the PCAM to argue customers do not receive a benefit from a particular factor affecting power costs unless the benefit of that particular factor exceeds the dead band and results in a credit. Consistent with the matching principle, the costs of the Exchange should be included in rates.³⁵⁰

VII. WAGES AND LABOR EXPENSE

122 As a part of this limited-issue filing, the Company excluded all post-test-year wage and labor adjustments from its proposed revenue requirement.³⁵¹ The Company calculated wages based on test-year-average full-time-equivalent (FTE) employee counts, and salaries and benefits.³⁵² Public Counsel and Boise originally proposed that the Company update its FTE count to the December 2015 level, resulting in a reduction to revenue requirement.³⁵³ In rebuttal, the Company agreed to update the FTE levels to the most recent count as of March 2016, provided wages were updated for known and measurable increases as of June 2016.³⁵⁴ Public Counsel and Boise agreed to this proposal, which resulted in a \$322,263 reduction from the Company's original filing.³⁵⁵

123 Public Counsel and Boise also propose that the Company update its pension and post-

³⁴⁸ Ball, TR. 345:9-12, 346:8-23.

³⁴⁹ *WUTC v. Pac. Power & Light Co.*, Dockets UE-140762, *et al.*, Order 09 ¶¶24-29 (May 26, 2015).

³⁵⁰ *See WUTC v. Avista Corp.*, Dockets UE-090134, *et al.*, Order 10 ¶94 (Dec. 22, 2009).

³⁵¹ Hymas, Exh. No. KCH-1T Revised (05/04/2016) 2:11-12.

³⁵² Hymas, Exh. No. KCH-1T Revised (05/04/2016) 3:17-18

³⁵³ Ramas, Exh. No. DMR-1T Revised (04/01/16) 37:6-38:3.

³⁵⁴ Hymas, Exh. No. KCH-1T Revised (05/04/2016) 4:19-5:9.

³⁵⁵ Hymas, Exh. No. KCH-1T Revised (05/04/2016) n.6.

retirement benefits other than pension (PBOP) to post-test-year levels, based on actuarial reports that show a reduction in 2016 expense.³⁵⁶ The Company objects to this adjustment. The Company agreed to update employee count and salary increases because these components, updated together, provide a fair estimate of total wages that will be paid during the rate effective period. In contrast, the pension and PBOP adjustments are one-sided and violate the matching principle by updating only aspects of employee benefits that are decreasing for 2016. There are other components of employment benefits that are increasing, such as medical insurance and 401K contributions. Once these components are considered, the pension and PBOP decreases are largely offset, demonstrating the reasonableness of the Company's approach.³⁵⁷

VIII. ALLOCATION ISSUES

A. Staff's Environmental Remediation Adjustment Violates Cost Causation.

124 The Company allocated the costs of its environmental remediation projects in the same way it has since the adoption of the WCA using a System Overhead (SO) factor.³⁵⁸ In its response testimony, Staff recommends that the Commission include in Washington rates only those remediation projects located within the west control area. Staff explains that it is not “reasonable for Washington ratepayers to bear the financial burden of environmental remediation activities that occur in jurisdictions that do not contribute to rendering or improving service to Washington.”³⁵⁹ Staff claimed that a west control area allocation would decrease rates.³⁶⁰

125 In rebuttal, the Company pointed out that Staff erred in its calculations by including only those remediation costs associated with facilities located within Washington and excluding costs

³⁵⁶ Ramas, Exh. No. DMR-1T Revised (04/01/16) 39:4-42:11; Mullins, Exh. No. BGM-1CT 30:10-14.

³⁵⁷ Hymas, Exh. No. KCH-3CX 1. This offset also applies to Public Counsel's proposed salary overhead adjustment (Ramas, Exh. No. DMR-1T Revised (04/01/16) 42:12-43:14), which the Company objects to for the same reasons.

³⁵⁸ McCoy, Exh. No. SEM-6T 15:7-10.

³⁵⁹ O'Connell, Exh. No. ECO-1T 33:5-7.

³⁶⁰ Ball, Exh. No. JLB-2 52.

associated with projects elsewhere in the west control area.³⁶¹ Staff compounded its error by then applying the SO factor to the Washington projects. When the correct WCA factors are applied to the west control area environmental remediation costs, Staff's proposal increases costs compared to the Company's filing.³⁶² Apparently in response, Staff revised its testimony, arguing that only the costs associated with environmental remediation projects located in Washington should be included in the revenue requirement.³⁶³

126 Staff's proposal is inconsistent with basic cost causation principles, which require that "cost causers should bear the costs they cause" and not receive benefits without paying the associated expense.³⁶⁴ As pointed out at hearing, Staff proposes to exclude from rates projects connected to the Jim Bridger plant, which serves Washington customers. Staff's proposal unfairly allows customers to receive the benefits of projects that contribute to rendering electric service in Washington without paying the expenses. In addition, Staff's proposal constitutes a piecemeal revision of the WCA, which the Commission has disfavored in the past.³⁶⁵

B. Boise's Transmission Adjustment is Based on a Misunderstanding of the WCA.

127 Boise proposes a modification to the WCA to allocate transmission operations and maintenance (O&M) in the same way that transmission revenues are allocated.³⁶⁶ Boise argues that the Company currently allocates transmission O&M on a system generation (SG) factor, which Boise claims is inappropriate because the Company owns significantly more transmission plant in the east than the west.³⁶⁷ In fact, as Boise conceded at the hearing, the WCA allocates

³⁶¹ McCoy, Exh. No. SEM-6T 15:20-16:6.

³⁶² McCoy, Exh. No. SEM-6T 16:8-10.

³⁶³ O'Connell, TR. 368:17-369:19.

³⁶⁴ *WUTC v. Tenino Tel. Co., et al.*, Dockets U-83-62, *et al.*, Third Suppl. Order, 1984 WL 1022554 at 21 (May 14, 1984).

³⁶⁵ Pacific Power's 2013 GRC Order ¶92.

³⁶⁶ Mullins, Exh. No. BGM-1CT 28:1-4.

³⁶⁷ Mullins, Exh. No. BGM-1CT 27:4-29:17.

transmission expense using the Control Area Generation West (CAGW) for the west control area and the Control Area Generation East (CAGE) for the east control area—fully accounting for the difference in east and west transmission assets.³⁶⁸ The Company uses the SG factor only for those expenses that cannot be assigned to a specific control area.³⁶⁹ Therefore, the current WCA appropriately accounts for transmission costs incurred to serve Washington customers.

C. Boise’s Allocation of General Office Expenses is Based on a Misreading of the WCA.

128 Boise claims that the Company erred in allocating certain expenses in FERC Account 557 using an SG factor, and that the WCA Manual requires the Company to apply an SO factor instead.³⁷⁰ On the contrary, according to the WCA Manual, the costs at issue in Account 557 are allocated using the SG factor—indeed, the SO factor does not even apply to Account 557.³⁷¹ Boise mistakenly relies on a section of the WCA that is specific to administration costs that are covered in Accounts 920-935—not Account 557.³⁷² As Boise appeared to concede at hearing, the Company properly applied the SG factor to the costs contained in Account 557.³⁷³

IX. DECOUPLING MECHANISM

129 Pacific Power’s proposal is consistent with the Commission’s Decoupling Policy Statement and is modeled on the mechanisms the Commission approved for PSE and Avista.³⁷⁴ The decoupling mechanism will provide for better fixed cost recovery in light of changes in usage due to weather and energy efficiency.³⁷⁵ The Company’s proposed mechanism is a revenue-per-customer decoupling mechanism that will compare the actual, non-weather adjusted

³⁶⁸ Mullins, TR. 399:23-400:14.

³⁶⁹ McCoy, Exh. No. SEM-6T 23:9-15; Mullins, TR. 400:9-21.

³⁷⁰ Mullins, Exh. No. BGM-1CT 32:5-11.

³⁷¹ Mullins, Exh. No. BGM-13CX 3, 29.

³⁷² McCoy, Exh. No. SEM-6T 22:4-11.

³⁷³ Mullins, TR. 408:14-409:6.

³⁷⁴ Steward, Exh. No. JRS-1T 10:1-18.

³⁷⁵ Steward, Exh. No. JRS-1T 9:18-20.

revenues per customer to the allowed revenue per customer, with any differences deferred.³⁷⁶

The mechanism will apply to residential, small general service, large general service, and irrigation customers.³⁷⁷ The decoupling mechanism will track non-net-power-related costs and exclude costs recovered through the basic charge—thus focusing on the fixed costs that the Company recovers through its non-net-power-cost volumetric charges.³⁷⁸

130 Staff generally supports the Company's proposal, but recommends five conditions for its approval.³⁷⁹ The Company only contests Staff's proposal for \$50,000 of shareholder funding for low-income conservation programs, which is unnecessary at this time. Total funding for low income weatherization is capped at \$1 million annually, a high cap intended to obviate the need for program revisions for several years. Despite the Company's partnering agencies' efforts, that cap has never been reached.³⁸⁰ The Company agreed to hold a collaborative to identify potential changes to improve the low income weatherization program. Based on the results of the collaborative, the parties will complete a proposal addressing plans or modifications to the program, including the need for additional funding, if warranted.³⁸¹

131 Staff also recommends a trigger requiring that the total decoupling deferral for any class of customers reach a threshold equivalent to +/-2.5 percent of allowed decoupled revenues before a rate adjustment is made.³⁸² Staff proposes increasing the rate cap from three to five percent. A

³⁷⁶ Steward, Exh. No. JRS-1T 10:18-11:1.

³⁷⁷ Steward, Exh. No. JRS-1T 11:1-3 (Schedules 16, 17, 18, 24, 36, and 40).

³⁷⁸ Steward, Exh. No. JRS-1T 11:16-21.

³⁷⁹ Ball, Exh. No. JLB-1T 45:10-28.

³⁸⁰ Steward, Exh. No. JRS-9T 6:2-6.

³⁸¹ Pacific Power's Response to Bench Request No. 10; Steward, Exh. No. JRS-9T 13:1-6. The parties have now agreed that a facilitator is unnecessary for this collaborative process because other dispute resolution options are available to the parties. Steward, Exh. No. 12:22-13:14. The LIBA discussions will address the potential impact of a third-energy-block rate design, funding, and enrollment levels, but a new study is not necessary to facilitate these discussions, and the information sought is publicly available in government records. Steward, Exh. No. JRS-9T 11:21-12:6, 12:22-14:5.

³⁸² Ball, Exh. No. JLB-1T 45:19-22.

trigger mechanism could improve rate stability and reduce customer confusion by avoiding small Schedule 93 adjustments. But Staff's threshold (2.5 percent) is too high and could undercut the goal of decoupling to provide the Company with better fixed cost recovery. Together with Staff's recommendation to increase the cap to five percent, the trigger would result in fewer annual adjustments that are larger in magnitude.³⁸³ The Company suggests that a more reasonable trigger is 0.5 percent, coupled with a three percent cap for rate increases to allow a more continual collection of the balancing account.³⁸⁴

132 NWEC also proposes that LIBA rate credits be increased proportionately with any annual decoupling-related increases in residential bills.³⁸⁵ This proposal makes little sense because decoupling rate adjustments are not part of base rates and are subject to changes to recover or refund associated balances. Consistent with this view, LIBA rate credits are not modified with price changes to other adjustment schedules that are not a part of base rates. Changing LIBA rate credits for temporary rate adjustments—up, down, or both—may result in confusion.³⁸⁶ The Company already proposed to increase the LIBA rate credits at two times the average residential increase for base rate changes, and agreed to include an assessment of the impact of decoupling on low income customers.³⁸⁷ If that study suggests that additional assistance is required, the parties can discuss the best approach at that time.

X. RATE DESIGN

133 While the Company has not generally proposed changes in rate spread or rate design, the Company did propose a change to rate design for the one Dedicated Facilities customer served

³⁸³ Steward, Exh. No. JRS-9T 9:12-15.

³⁸⁴ Steward, Exh. No. JRS-9T 9:10-19.

³⁸⁵ Cavanagh, Exh. No. RC-1T 3:1-5.

³⁸⁶ Steward, Exh. No. JRS-9T 11:3-4.

³⁸⁷ Steward, Exh. No. JRS-9T 5:9-6:13.

under Schedule 48T. Specifically, for the Dedicated Facilities customer, the Company proposes a higher increase to demand charges and a lower increase to other billing elements. Overall, the Company's proposal results in the same average increase to Dedicated Facilities that applies to the remaining customers on Schedule 48T.³⁸⁸

134 Boise opposes the Company's proposal, and instead proposes a uniform rate design for all of Schedule 48T.³⁸⁹ Boise's proposal ignores the fact that Dedicated Facilities are treated as a separate class from all other Schedule 48T customers in cost of service studies because of the significant differences between Dedicated Facilities and all other Schedule 48T customers.³⁹⁰

135 Boise's proposal also unfairly results in a much lower increase for the Dedicated Facilities customer than other Schedule 48T customers. Under Boise's proposal, Dedicated Facilities receive a rate increase of 47 and 43 percent of the average increase in year one and year two, respectively, while remaining Schedule 48T customers receive a rate increase of 148 and 152 percent of the average in year one and year two, respectively.³⁹¹ Boise's asymmetrical proposal is particularly egregious given that the Dedicated Facilities customer is currently at 96 percent cost of service, whereas all other Schedule 48T customers are at 102 percent of cost of service.³⁹² The Commission has found that the "principle of gradualism is an important consideration" when a single customer proposes changes that will impact the entire class and that increases of 114 percent of the average were "too extreme."³⁹³ Boise's proposal

³⁸⁸ Steward, Exh. No. JRS-9T 1:20-2:3.

³⁸⁹ Mullins, Exh. No. BGM-1CT 43:4-6 (25 percent increase to the basic charge and spreading the remaining allocated increase to demand charges).

³⁹⁰ Steward, Exh. No. JRS-9T 17:10-15. The Dedicated Facilities customer is approximately 10 times larger than the next largest Schedule 48T customer, and that one customer's energy usage is over 50 percent of total Schedule 48T energy sales.

³⁹¹ Steward, Exh. No. JRS-9T 16 Table 1; Steward, Exh. No. JRS-17.

³⁹² Steward, Exh. No. JRS-9T 17:18-22.

³⁹³ Pacific Power's 2014 GRC Order ¶¶202, 226.

violates gradualism, is extreme, and is fundamentally unfair to other Schedule 48T customers.

XI. LOW-INCOME BILL ASSISTANCE PROGRAM

136 Consistent with the five-year LIBA plan approved in docket UE-111190, the Company proposes to increase LIBA benefits by two times the residential rate increase in both 2016 and 2017.³⁹⁴ Parties support Pacific Power's proposal and appear willing to collaborate regarding the program's future.³⁹⁵ After this case, the Company will file changes to the LIBA program surcharge, to recover the increase in the participant benefits or make other necessary changes.³⁹⁶

XII. CONCLUSION

137 Pacific Power respectfully requests that the Commission approve the Company's proposals in this proceeding for the reasons set forth above.

Respectfully submitted this 22nd day of June, 2016.



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³⁹⁴ Dalley, Exh. No. RBD-1T 19:6-15.

³⁹⁵ Dalley, Exh. No. RBD-3T 27:10-14.

³⁹⁶ Steward, Exh. No. JRS-1T 9:5-14. The Energy Project indicates that the LIBA program has a goal "of 25 percent of all eligible customers being certified by the year 2015." Collins, Exh. No. SMC-1T 5:11-12. The 25 percent benchmark was a target for the number of customers certified as eligible for a two-year period, not for the total number of all eligible customers. Steward, Exh. No. JRS-9T 12:7-21. Also, the rate increase for the residential class is the same as the proposed increase for all other customers. Steward, Exh. No. JRS-9T 14:6-9; Collins, Exh. No. SMC-1T 9:19-21.