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September 28, 2020

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 374 – In the Matter of PACIFICORP d/b/a PACIFIC POWER'S Request for a General Rate Revision.

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp's Opening Brief. Confidential material in support of the filing will be provided to qualified parties under Protective Order No. 20-040 via encrypted zip file.

Please contact this office with any questions.

Sincerely,

Katherine McDowell

Attachment

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of the confidential pages of PacifiCorp's **Opening Brief** on the parties listed below that have signed the modified protective order via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

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Dated this 28th day of September, 2020.

Alisha Till

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

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

PACIFICORP'S OPENING BRIEF

September 28, 2020

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I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) requests approval for a base rate change that, in conjunction with other rate changes also taking effect January 1, 2021, will result in an overall rate decrease of $8.8 million, or 0.7 percent. Offsetting rate changes include a significant reduction in net power costs (NPC) proposed in the 2021 Transition Adjustment Mechanism (TAM) stipulation[1] and tax savings under the Tax Cuts and Jobs Act of 2017 (TCJA). The proposed base rate change in this case is $47.5 million, or approximately 4 percent, and reflects both the Company's prudent and necessary investments made on behalf of customers since its last general rate case seven years ago, as well as the need for ongoing investments for a resilient energy future.

PacifiCorp has invested approximately $10 billion in the transformation of its system in the past seven years.[2] These investments—most of which are uncontested in this case—include developing approximately 1,400 megawatts (MW) of new wind resources, repowering 1,040 MW of existing wind resources, constructing a major new transmission line, installing advanced metering infrastructure (AMI), and accelerating coal plant depreciation and retirements. PacifiCorp has worked diligently to bring significant value to customers in this case, while also ensuring that the net impact on January 1, 2021, will be a rate decrease.

As PacifiCorp detailed in its testimony, Prehearing Brief, and at hearing, PacifiCorp has fully supported its recommendations contested by other parties, including its proposed cost of capital, the need for a fair and more balanced NPC recovery mechanism, and the prudence of the

[1] On August 18, 2020, the parties filed a comprehensive, all-party Stipulation in the 2021 TAM. The parties agreed to a rate decrease of $49.8 million, or 3.8 percent on an overall basis, subject to the TAM Final Update. The rate decrease is based on the assumption that the Company's new wind resources will be in-service by the January 1, 2021 rate effective date in this case and in the 2021 TAM; paragraph 18 addresses the matching of costs and benefits in the event of any delay in commercial operation dates. *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2021 Transition Adjustment Mechanism*, Stipulation, Docket UE 375 (Aug. 18, 2020).
[2] PAC/2100, Kobliha/7.

Company's emissions control and transmission investments. At hearing, PacifiCorp's witnesses bolstered the record supporting each of these key issues. In contrast, Staff failed to adequately explain or support its cost of capital and transmission adjustments, and Sierra Club failed to identify any basis for disallowing the Company's emissions control investments at the Jim Bridger or Hayden plants. The record on these issues is clear and decisive in PacifiCorp's favor.

Even though the overall rate change is a decrease, Staff and intervenors propose significant disallowances in this case—disallowances that, when combined, would seriously jeopardize the Company's credit rating and hinder its ability to implement Oregon energy policy. The Commission is tasked with establishing rates that are just and reasonable on a holistic basis.[3] Notably, no party attempts to tally the impact of its combined adjustments in this case, despite simultaneously advocating for the Commission to set rates "on a comprehensive basis."[4] When viewed as a whole, the adjustments proposed are unsupportable.

For instance, the combined impact of Staff's adjustments would reduce the Company's base rates by approximately $40.1 million—reducing the Company's overall rates on January 1, 2021 by $96.4 million, or 7.3 percent—just as PacifiCorp embarks on a major capital investment program to meet the future needs of Oregon customers. Similarly, the Alliance of Western Energy Consumers' (AWEC) combined adjustments would reduce the Company's revenue requirement request in this proceeding by $65.3 million, reducing the Company's overall rates on January 1, 2021 by $74.1 million or 5.6 percent. Oregon Citizens' Utility Board's (CUB) adjustments would [redacted] in this proceeding—reducing the Company's overall rates on January 1, 2021, by $[redacted] or [redacted]. Finally, Sierra Club's adjustments would reduce the Company's revenue requirement request in this case by

[3] ORS 756.040.
[4] CUB/100, Jenks/33.

$32.4 million—reducing the Company's overall rates on January 1, 2021 by $41.2 million or 3.1 percent.[5] These unprecedented and damaging rate decreases fail the "just and reasonable" standard of ORS 756.040, especially given the fact that PacifiCorp's Oregon rates are already some of the lowest in the nation.[6]

At this critical moment in Oregon's energy policy development and implementation, PacifiCorp's rate request ensures that the Company can continue to provide service safely and reliably and invest in customers' future needs, all while avoiding adverse customer rate impacts. The Commission should approve PacifiCorp's request as just, reasonable, and necessary to achieve Oregon's energy policy goals.

II. COST OF CAPITAL

A. <u>Overview</u>

PacifiCorp's cost of capital, or "'[c]ost of financing[,]' refers to the costs that a utility incurs, or is deemed to incur, in order to finance capital projects," including both the cost of debt and the cost of equity.[7] Under ORS 756.040, a utility's cost of capital must be set at a level commensurate with returns of businesses with comparable risks and must be sufficient to ensure confidence in the utility's financial integrity, allowing it to maintain its credit rating and attract capital necessary to maintain, improve, and expand its provision of safe and reliable service.[8]

PacifiCorp's recommended cost of capital responds to multiple challenges facing the Company, while still maintaining low overall rates.[9] These challenges include unprecedented

[5] Attachment A (Adjustment Appendix) sets out the itemized and combined revenue requirement adjustments proposed by Staff, AWEC, CUB, and Sierra Club, as well as PacifiCorp's updated revenue requirement request in this proceeding.
[6] PAC/3400, Kobliha/5.
[7] *In the Matter of Pub. Util. Comm'n of Or., Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket UM 1909, Order No. 20-147 at 2 (Apr. 30, 2020).
[8] ORS 756.040(1); *see also Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944); *Gearhart v. PUC*, 356 Or. 216, 220 (2014) (*citing* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 170 (2d ed 1988)).
[9] PAC/3400, Kobliha/5.

volatility in the capital markets, cash flow restrictions from the TCJA, major investments identified in the 2019 Integrated Resource Plan (IRP) and required by Oregon's energy and wildfire policy directives, and increased rating agency scrutiny and downgrades. PacifiCorp proposes a reduction in its weighted average cost of capital (WACC) to 7.46 percent, a decrease of 16 basis points (bps) from its current WACC of 7.62 percent.[10] As set forth below, this includes no change to PacifiCorp's current return on equity (ROE) of 9.8 percent, an increase in the equity ratio from 52.10 percent to 53.52 percent, and a decrease in long-term debt costs from 5.25 percent to 4.77 percent. PacifiCorp conservatively recommends maintaining the cost of debt reflected in its initial filing, which does not account for an increase associated with its most recent long-term debt issuance.[11] PacifiCorp's cost of debt recommendation is lower than the 4.824 percent recommended by Staff.[12]

PacifiCorp's Recommended Cost of Capital

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	46.47%	4.77%	2.22%
Preferred Stock	0.01%	6.75%	-----%
Common Stock Equity	53.52%	9.8%	5.24%
Total	100.0%		7.46%

B. Capital Structure

PacifiCorp's equity ratio in the 2021 test year (Test Year) is forecast to be 53.52 percent.[13] This equity ratio is necessary for PacifiCorp to retain its current credit rating, which will ensure continued access to capital markets and low-cost debt financing, particularly during the current economic turmoil and increased capital spending.[14]

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[10] PacifiCorp's current cost of capital was approved in *In the Matter of PacifiCorp, dba Pacific Power, Request for General Rate Revision*, Docket UE 263, Order No. 13-474, App. A at 4 (Dec. 18, 2013).
[11] PAC/2100, Kobliha/10.
[12] Staff/1900, Muldoon-Enright-Dlouhy/68.
[13] PAC/300, Kobliha/18-20; PAC/2100, Kobliha/2-9; PAC/3400, Kobliha/2-12.
[14] PAC/3400, Kobliha/2.

1. PacifiCorp's equity ratio offsets the adverse impact of the TCJA on cash flows.

The Commission has acknowledged the negative effect of the TCJA on utility cash flows and credit ratings,[15] which is a concern shared by PacifiCorp's regulators in other states.[16] These negative effects continue to impact PacifiCorp as it works with regulators to reflect tax reform in rates—a process that is very much ongoing, as evidenced by this case. Moody's has been downgrading utilities throughout 2019 and 2020 as a result of the negative cash flow implications of tax reform, providing additional evidence of the ongoing impact of tax reform on utility credit metrics.[17] The negative impact of tax reform has been compounded by the risks associated with the current capital market conditions. In April 2020, S&P downgraded the outlook of the entire North American utilities sector.[18] Staff testified that ratings downgrades are accelerating.[19]

To offset the negative impact of tax reform, many utilities, including PacifiCorp, have increased their equity ratios.[20] By adding a thicker equity layer and maintaining its current 9.8 percent ROE, PacifiCorp hopes to mitigate the financial risk caused by tax reform, allowing the Company to maintain its cash flow metrics and current credit ratings.

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[15] *In the Matter of Avista Corporation, dba Avista Utilities, Application for Authorization to Issue and Sell $600,000,000 of Debt Securities*, Docket UF 4313, Order No. 19-249, App. A at 8 (July 30, 2019) (after TCJA-related downgrade by Moody's, restoration of previous credit rating will require supportive regulatory environment and achieving target metrics); *In the Matter of Portland Gen. Elect. Co. Request for Authority to Extend the Maturity of an Existing $500 Million Revolving Credit Agreement*, Docket UF 4272(3), Order No. 19-025, App. A at 9 (Jan. 23, 2019) (Commission will continue to monitor Moody's post-TCJA approach to credit ratings because interest rates applicable to PGE depend on its credit ratings).
[16] PAC/2200, Bulkley/33-34 (noting that Wyoming and Utah commissions have also acknowledged cash flow issues created by TCJA).
[17] PAC/2200, Bulkley/34-35.
[18] PAC/2200, Bulkley/24.
[19] Staff/200, Muldoon-Enright/47; Staff/210, Muldoon-Enright/155 ("Corporate bonds are being downgraded at breakneck speeds, demonstrating the threat posed to companies' balance sheets by the coronavirus crisis.").
[20] Staff/1911, Muldoon-Enright-Dlouhy/466.

2. PacifiCorp's increased investment in new renewable resources requires a strong credit rating supported by the Company's actual equity ratio.

During periods of intense capital spending, a thicker equity ratio is necessary to maintain credit metrics, particularly ratio of funds from operations to debt that is the key metric used by Moody's to set PacifiCorp's credit rating.[21] PacifiCorp's expected capital expenditures in 2020-2022 are substantially higher than its historical expenditures going back to 2009.[22]

3. PacifiCorp's actual equity ratio is consistent with the proxy group used to estimate PacifiCorp's ROE.

The operating utilities that comprise the proxy group used by PacifiCorp and AWEC to estimate the Company's ROE have comparable equity ratios to PacifiCorp, ranging from 39.98 percent to 61.54 percent, with an average of 52.87 percent.[23] PacifiCorp's equity ratio of 53.52 percent is only slightly above this average, and well below the higher-end ratios. If the Commission were to adopt a hypothetical capital structure with more debt—as Staff and AWEC recommend—then the ROE would need to be increased to reflect the higher financial risk.[24] The "greater the debt ratio, the greater is the return required by equity investors."[25] Staff's ROE was explicitly calculated assuming a 53.52 percent equity ratio, not Staff's lower 51.86 percent ratio.[26]

4. AWEC's and Staff's equity ratio relies on flawed and outdated analysis.

Both AWEC and Staff propose an equity ratio of 51.86 percent based on Mr. Gorman's flawed recommendation.[27] First, Mr. Gorman's analysis is fundamentally backward looking.[28]

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[21] PAC/2100, Kobliha/3.
[22] PAC/2100, Kobliha/7.
[23] PAC/400, Bulkley/7; PAC/413.
[24] PAC/2200, Bulkley/70, Morin at 484.
[25] Roger A. Morin, PhD, *New Regulatory Finance*, Public Utilities Reports, Inc. at 484 (2006).
[26] PAC/2200, Bulkley/70 (Hamada equation used PacifiCorp's recommended equity ratio).
[27] AWEC/600, Gorman/4-5; UE 374 Evidentiary Hearing Transcript (Sept. 9, 2020) (hereinafter "Sept. 9, 2020, Tr.") 66:23-67:3.
[28] AWEC/200, Gorman/22-23 (recommending equity ratio based on financial capital structure from 2014-2018).

Mr. Gorman's equity ratio is based on historical data that preceded the TCJA and reflects a period in which PacifiCorp's capital expenditures were substantially lower.[29] The Company's actual equity ratio in 2014 is not sufficient to support its credit rating in 2021.

Second, Mr. Gorman relies on outdated analysis to support his claim that 51.86 percent equity will allow PacifiCorp to maintain its current credit rating. Mr. Gorman admitted at hearing that he never updated his credit metric analysis even as the inputs changed during this case.[30] He also admitted that, without rerunning his analysis using updated information, there is no way to know how the updated inputs would impact the results.[31] Mr. Gorman also tested his cost of capital recommendations against only S&P's credit metrics, even though Staff agrees with PacifiCorp that it is reasonable to focus on Moody's rating as it is the lower of the two ratings.[32]

Third, instead of updating his credit metric analysis, in rebuttal Mr. Gorman pointed to a recent decision from Washington approving a 9.4 percent ROE and a 48.5 percent equity ratio for Puget Sound Energy (PSE).[33] The Commission previously refused to rely on a Washington Utilities and Transportation Commission (Washington Commission) capital structure decision as a reasonableness check because Washington considers short-term debt in its calculations.[34] In addition, Moody's determined that the PSE result was "credit negative," in part because the Washington Commission "authorized a below industry average return on equity of 9.4%."[35]

[29] PAC/2100, Kobliha/7.
[30] Sept. 9, 2020, Tr. 41:9-43:25.
[31] Sept. 9, 2020, Tr. 58:16-18.
[32] Staff/1900, Muldoon-Enright-Dlouhy/24.
[33] AWEC/600, Gorman/6-7.
[34] *In the Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket UG 288, Order No. 16-109 at 6 (Mar. 15, 2016).
[35] CUB/401, Jenks/1.

C. Cost of Equity

1. Maintaining PacifiCorp's current 9.8 percent ROE is reasonable.

PacifiCorp's expert witness, Ms. Ann Bulkley, recommends an ROE range for PacifiCorp between 9.75 and 10.25 percent.[36] Given current circumstances, including the economic turmoil created by the COVID-19 pandemic, PacifiCorp recommends no change to its currently authorized ROE of 9.8 percent, which conservatively falls at the lower end of the reasonable range.

PacifiCorp's recommendation considers the results of several ROE estimation models and reflects current market indicators of increasing equity costs caused by recent economic events. Staff and AWEC recognize that market conditions have affected the assumptions used in their ROE estimation models but fail to adjust their recommendations accordingly. By relying too heavily on the discounted cash flow (DCF) model, and by failing to use forward-looking assumptions in the Capital Asset Pricing Model (CAPM), Staff and AWEC understate the forward-looking cost of equity.

PacifiCorp's recommendation to maintain its currently authorized ROE is supported by robust analysis from a range of generally accepted ROE estimation models, reflects current and prospective capital market conditions, and is consistent with authorized ROEs for integrated electric utilities in other jurisdictions. During these difficult economic times, a 9.8 percent ROE reasonably balances PacifiCorp's need to maintain access to capital with concerns for customers.

2. The Commission should consider all ROE estimation models.

To address the challenges of setting an ROE during times of market uncertainty and significant market intervention by the Federal Reserve, the Commission should evaluate all

[36] PAC/3500, Bulkley/12, 14-15.

available estimation models to inform the selection of a reasonable ROE for PacifiCorp. For ratemaking purposes, there are four generally accepted ROE estimation methodologies: DCF, Risk Premium, and CAPM, which are market-oriented, and Expected Earnings, which is accounting oriented.[37] As Dr. Roger Morin explains, experts agree that "[n]o one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of informed judgment."[38] Dr. Morin cautions, "[r]eliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data."[39] Ms. Bulkley is the *only* witness in this case that presented model results from all four generally accepted methodologies.[40] Ms. Bulkley's robust modeling results inform her ROE range and 9.8 percent point recommendation.

a. <u>DCF results are understating equity costs.</u>

Current market conditions strongly indicate that the DCF model is understating equity costs. Because utility stock prices are well above historical levels, the dividend yield component of the DCF model is well below historical levels, which causes the DCF models to understate equity costs.[41] Although utility stock prices have decreased over the course of this case, the share prices are still well above historical levels. The CAPM and Risk Premium results show the cost of equity for utilities is higher than the ROE estimates produced by the DCF model at this time.[42]

Regulators across the country have recognized that DCF results are now less reliable.[43]

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[37] Morin at 428 (Expected Earnings are also referred to as Comparable Earnings); *see also* Robert L. Hahne & Gregory E. Aliff, *Accounting for Public Utilities* at §9.03, 9-11 (2018).
[38] Morin at 428.
[39] Morin at 428; *id.* at 430 (citing scholarship by Eugene Brigham, Stewart Myers, James C. Bonbright, Albert T. Danielsen, and David R. Kamerschen for the proposition that regulators should rely on more than one model).
[40] *See* PAC/400, Bulkley/2; PAC/3501.
[41] PAC/2200, Bulkley/61.
[42] PAC/2200, Bulkley/62.
[43] PAC/400, Bulkley/40-42, PAC/2200, Bulkley/36, 58.

For example, the Federal Energy Regulatory Commission (FERC) now gives equal weight to DCF, CAPM, and Risk Premium results, instead of focusing exclusively on the DCF model.[44] Applying FERC's methodology to PacifiCorp's reply results produces an ROE estimate of 9.69 percent.[45] In addition, Mr. Gorman recently acknowledged that the DCF model understates ROEs when he relied on CAPM and Risk Premium results for setting another utility's ROE.[46]

Staff is the only party that relies on exclusively one model. At hearing, Staff claimed that it relied on the CAPM and Constant Growth DCF model to inform its point recommendation.[47] But this is contradicted by Staff's pre-filed testimony, in which Staff's reasonable range is established exclusively by its Multi-Stage DCF results.[48] Staff also testified that it "does not use CAPM when setting rates"[49] and that Staff "only puts weight on the multi-stage DCF models."[50] While Staff acknowledges that its updated CAPM and Constant Growth DCF models now point to the upper end of its ROE range, not the mid-point, Staff's proposed ROE did not change.[51]

Staff's testimony cites a report from Regulatory Research Associates (RRA) that was "informative to Staff."[52] That RRA report "discuss[ed] the methods that public utility regulators use to set" ROEs.[53] According to RRA, "[n]o one method is universally recognized, and utility commissions often incorporate multiple methodologies and other subjective interpretations in rendering their final decisions."[54]

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[44] PAC/2200, Bulkley/58-59.
[45] PAC/2200, Bulkley/59.
[46] PAC/2200, Bulkley/111-112.
[47] Sept. 9, 2020, Tr. 64:17-66:22.
[48] *See* Staff/1904.
[49] Staff/1900, Muldoon-Enright-Dlouhy/56, 80.
[50] Staff/1900, Muldoon-Enright-Dlouhy/73.
[51] *Compare* Staff/1904 (CAPM and Single Stage DCF point to top of Staff's three stage DCF modeling results) to Staff/205 (CAPM and single stage point to the middle of the three stage results).
[52] Staff/1900, Muldoon-Enright-Dlouhy/41.
[53] Staff/1900, Muldoon-Enright-Dlouhy/41; Staff/1911, Muldoon-Enright-Dlouhy/53.
[54] Staff/1911, Muldoon-Enright-Dlouhy/53.

b. Current market conditions support reliance on forward-looking models.

Given current market conditions, it is critical to evaluate model results that consider projected market data because those models reflect economists' expectations for the market conditions that will prevail when rates are in effect.[55] PacifiCorp's CAPM, Empirical CAPM (ECAPM), and Bond Yield Plus Risk Premium analysis all include projected market data and provide a reasonable estimate of PacifiCorp's equity cost during the rate year.[56] The results of these models range from 9.26 percent to 12.92 percent.[57]

3. The market turmoil caused by the COVID-19 pandemic increased equity costs.

Capital market conditions have changed dramatically since PacifiCorp filed this case in February 2020. Heightened volatility in equity and bond markets, much wider credit spreads between government and utility bonds, and significantly higher beta coefficients—which are the measure of risk used in the CAPM—suggest that the cost of equity has risen.[58] Both the DCF model and the CAPM are now producing higher ROEs based on market data that incorporates the impact of recent economic conditions.

a. Market volatility has increased risk and uncertainty, which indicates higher equity costs.

Quantifiable market data demonstrates that volatility has increased significantly since February 2020. In particular, the Chicago Board Options Exchange Volatility Index, which measures equity market volatility, reached levels unseen since the Great Recession of 2008/2009.[59] Although volatility has declined since the initial uncertainty in April and May, it remains well above pre-pandemic levels.[60]

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[55] PAC/2200, Bulkley/25.
[56] PAC/2200, Bulkley/33.
[57] PAC/3501, Bulkley/1.
[58] PAC/3500, Bulkley/2.
[59] PAC/2200, Bulkley/19.
[60] PAC/2200, Bulkley/20.

In rebuttal, Staff testified that stocks have become "much more volatile" because of investors' changing expectations of the economy.[61] According to Staff, that volatility has "caused daily returns to vary wildly" and markets have become even more turbulent as investors plan around volatility.[62] Staff concluded the market turbulence "has translated even into utility investment even though utilities have long-since been believed to be stable."[63] Staff testified that, "[w]hile a utility stock usually has a fairly low volatility compared to other stocks in the market," beta coefficients "have risen markedly," which is evidence that utilities are experiencing the same increased volatility as the broader market.[64]

b. Utility stocks are not safe-haven investments.

Utility stocks are often viewed as relatively safe investments during times of economic uncertainty when investors seek stable returns and lower volatility.[65] In this financial crisis, however, market volatility has not driven investors to utility equities, nor have utilities played their traditional role as a safe-haven investment.[66] Utility stocks have underperformed during the pandemic relative to the broader market, in part because of reduced demand for electricity.[67] This underperformance is evidence that it has become more difficult—and expensive—for utilities to attract capital.[68] Utilities are underperforming the broader market because investors view the risk/reward relationship as less attractive than other market sectors.[69]

Staff's testimony on this point is contradictory. Staff testified, "Utilities have long been

[61] Staff/1900, Muldoon-Enright-Dlouhy/16; *id.* at 83 ("volatility in fixed income is diminishing while volatility in equities has risen"); *id.* at 99 (between Staff's opening and rebuttal stock market has been "particularly volatile").
[62] Staff/1900, Muldoon-Enright-Dlouhy/16-17.
[63] Staff/1900, Muldoon-Enright-Dlouhy/17.
[64] Staff/1900, Muldoon-Enright-Dlouhy/82.
[65] *See, e.g.*, AWEC/200, Gorman/11.
[66] PAC/2200, Bulkley/32.
[67] PAC/3500, Bulkley/8.
[68] PAC/3500, Bulkley/8.
[69] PAC/3500, Bulkley/9.

considered one of the safest assets for investors," and "Staff's view tallies with that of market experts—this fundamental truth of financial markets is unlikely to change, despite increased market volatility."[70] But the "market experts" Staff cites conclude that "[u]tilities' stocks have long been seen as a safe place to park cash and collect steady dividends. *But as the coronavirus spread around the world this year, they have been more volatile than the broader market*."[71] Staff also cites an article from S&P Global Market Intelligence explaining that the S&P 500 and S&P 500 Utilities index reached their widest spread since July 2003, "as utilities endured weeks of underperformance while the broad market was thriving[.]"[72]

AWEC simply claims that "utility investments have been less volatile during extreme market downturns" but provides no support and fails to square this conclusion with the observable market evidence from this market downturn.[73]

c. Updated ROE model results show increased equity costs.

Consistent with the broader market indicators, the record demonstrates that PacifiCorp's ROE increased due to the COVID-19 pandemic. After incorporating the market impact of the pandemic into its model results in its reply testimony, PacifiCorp's analysis showed materially higher ROEs. The onset of the pandemic decreased utility stock prices, which, in turn, increased the dividend yield component of the DCF model.[74] PacifiCorp's Constant Growth DCF results increased by 24 bps, while the Multi-Stage DCF results increased by 70 bps.[75] Importantly, the increased dividend yields remain below historical averages and therefore the DCF model still understates equity costs.[76]

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[70] Staff/1900, Muldoon-Enright-Dlouhy/62.
[71] Staff/1911, Muldoon-Enright-Dlouhy/184 and 259 (same article included twice in Staff/1911) (emphasis added).
[72] Staff/1911, Muldoon-Enright-Dlouhy/267.
[73] AWEC/200, Gorman/11.
[74] PAC/2200, Bulkley/14, 80.
[75] PAC/2200, Bulkley/14.
[76] PAC/2200, Bulkley/14, 30-31.

Like the DCF results, PacifiCorp's CAPM results increased by 96 bps in reply testimony, and ECAPM results increased by 76 bps.[77] In both cases, the increase was primarily driven by updated and increased beta coefficients, which increase the risk premium for holding utility stocks in the models. The increase in beta coefficients indicates that utility stock prices have moved more in line with the market than prior to the pandemic. In surrebuttal, the CAPM and ECAPM results increased even more dramatically due to fully updated beta coefficients.[78]

Staff is the only other party that updated its models. Staff's initial model results and recommendation did not "capture the full economic shock of the 2020 COVID-19 pandemic."[79] Staff's recommended ROE range was based exclusively on its Multi-Stage DCF model and showed a range of 8.52 percent to 9.39 percent, with a recommended ROE of 9.0 percent.[80] After updating its analysis in rebuttal, Staff's ROE range—which was again based exclusively on the results of its Multi-Stage DCF model—increased to 8.57 percent to 9.42 percent.[81] Staff's Constant Growth DCF model showed an even larger ROE increase—from 8.9 percent in opening testimony to 9.5 percent after accounting for the impacts of the pandemic.[82] Staff conceded at hearing that the higher model results were caused by decreasing utility stock prices, which increased the dividend yield of the DCF model.[83] Staff's CAPM results showed even more dramatic changes, increasing from 7.7 percent to 9.3 percent, driven by higher beta coefficients.[84] Although PacifiCorp disagrees with Staff's original and updated DCF and CAPM modeling, the results do establish increasing equity costs caused by current market conditions.

[77] PAC/2200, Bulkley/14.
[78] PAC/2201; PAC/3501.
[79] Staff/200, Muldoon-Enright/9.
[80] Staff/200, Muldoon-Enright/9.
[81] Staff/1900, Muldoon-Enright-Dlouhy/2.
[82] Staff/207; Staff/1906.
[83] Sept. 9, 2020, Tr. 68:8-69:24.
[84] Staff/206; Staff/1905.

AWEC's expert witness did not update any of his ROE models. But Mr. Gorman's workpapers similarly point to higher equity costs resulting from the pandemic. For example, Mr. Gorman relied on a report from Duff & Phelps that noted that the COVID-19 pandemic "[redacted]"[85] The report noted that equity volatility [redacted][86] Based on these market conditions, Duff & Phelps [redacted].[87]

4. PacifiCorp's recommended ROE is in line with national averages.

Regulatory decisions in other jurisdictions provide a basic test of reasonableness and a benchmark considered by investors when evaluating PacifiCorp's authorized ROE against other regulated utilities with comparable risk.[88] From January 2018 through May 2020, the average authorized return for vertically integrated utilities was 9.70 percent, with a median of 9.73 percent.[89] Of the 58 decisions, 44 included an authorized ROE between 9.5 percent and 10.0 percent.[90] Six out of seven decisions issued in 2020 by jurisdictions RRA considers credit-supportive were from 9.7 percent to 10.02 percent for integrated utilities.[91]

Staff's and AWEC's recommended ROEs of 9.0 percent and 9.2 percent, respectively, are outliers. Only 1 of 58 decisions for integrated utilities since January 2018 had an authorized ROE of 9.0 percent or less.[92] Even the three decisions issued in 2020 by jurisdictions that are

[85] PAC/4503 at 1.
[86] PAC/4503 at 1.
[87] PAC/4503 at 1.
[88] PAC/2200, Bulkley/9.
[89] PAC/2200, Bulkley/9.
[90] PAC/2200, Bulkley/11.
[91] PAC/3500, Bulkley/10.
[92] PAC/2200, Bulkley/49.

less credit supportive were either 9.40 or 9.45 percent, above both Staff's and AWEC's positions.

Staff, AWEC, and CUB support their recommended ROEs by pointing to authorized ROEs for delivery-only utilities.[93] Such a comparison is inapt given the different risk profiles for delivery-only utilities. Indeed, both Staff and AWEC rely on RRA reports that explain that the average annual ROE for vertically integrated utilities like PacifiCorp are typically 30 to 65 bps above those for delivery-only utilities.[94] According to RRA, the higher ROE for vertically integrated utilities arguably reflects the increased risk associated with generation ownership.[95] Moody's also views vertically integrated utilities as higher risk than delivery-only utilities because "power generation is the highest-risk component of the electric utility business[.]"[96]

Market data confirms that the relevant comparator for PacifiCorp is vertically integrated utilities. Staff's testimony included a report from S&P Global Market Intelligence pointing out that Staff's 9.0 percent ROE is "below the 9.72% average equity return accorded *vertically integrated electric utilities nationwide* in cases decided in the first three months of 2020 and the 9.73% average ROE in full year 2019[.]"[97] Staff's and AWEC's own RRA data shows the industry average ROE for vertically integrated utilities was 9.73 percent for 2019, 9.72 percent for the first quarter of 2020, and 9.67 percent for the first half of 2020.[98] The median ROE for vertically integrated utilities like PacifiCorp for the first quarter of 2020 was 9.75 percent, which was higher than the median ROE for 2019.[99] These results demonstrate the reasonableness of PacifiCorp's recommended ROE and the unreasonableness of Staff's, AWEC's, and CUB's

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[93] Staff/1900, Muldoon-Enright-Dlouhy/40-41; AWEC/603; CUB's Prehearing Brief at 15.
[94] Staff/1911, Muldoon-Enright-Dlouhy/469; Sept. 9, 2020, Tr. 52:7-14; 83:20-23.
[95] Staff/1911, Muldoon-Enright-Dlouhy/469.
[96] PAC/2200, Bulkley/47.
[97] Staff/1911, Muldoon-Enright-Dlouhy/154 (emphasis added).
[98] Staff/1911, Muldoon-Enright-Dlouhy/466; PAC/4506 at 3; PAC/4504 at 1.
[99] PAC/4506 at 3.

recommendations.

Instead of updating its ROE models, AWEC's rebuttal testimony simply provided updated data on authorized ROEs.[100] AWEC's data improperly included both vertically integrated and delivery-only utilities. Had AWEC examined only vertically integrated utilities of comparable risk to PacifiCorp, its results would have shown that the mean authorized ROE in 2020 for vertically integrated utilities in its exhibit was 9.64 percent and the median is 9.7 percent—both results that align with PacifiCorp's recommended ROE, but not AWEC's.

5. AWEC's singular focus on interest rates ignores broader market conditions.

Because Mr. Gorman did not update his models in rebuttal testimony, he relied on declining interest rates to support his recommended ROE.[101] But the Commission should not focus on declining interest rates in isolation without considering the market conditions that led to those declining interest rates.[102] For example, RRA has explained that "the gap between authorized ROEs and interest rates widened somewhat [since 1990], largely as a result of an often-unstated understanding by regulators that the drop in interest rates caused by Federal Reserve intervention was unusual,"[103] which is consistent with current capital market conditions. Moreover, as Ms. Bulkley explained at hearing, while the Federal Reserve is controlling short-term rates, they have no intention of controlling the long-term rates that are used in RRA's comparison with authorized ROEs and in the CAPM and Risk Premium methodologies.[104]

AWEC and Staff ignore the increasing spread between government and utility bond yields, which shows they failed to consider higher risk in their recommendations.[105] PacifiCorp's

[100] AWEC/603.
[101] *See, e.g.*, AWEC/600, Gorman/7.
[102] PAC/2200, Bulkley/17
[103] Staff/1911, Muldoon-Enright-Dlouhy/468.
[104] Sept. 9, 2020, Tr. 20:19-25.
[105] PAC/2200, Bulkley/27.

analysis further demonstrates that the historically strong correlation between utility bond yields and dividend yields has not held up during the recent economic turmoil.[106] PacifiCorp's *quantitative* analysis shows that declining utility bond yields do not indicate declining equity costs, contrary to Mr. Gorman's *qualitative* testimony.

6. AWEC's non-updated DCF models understate PacifiCorp's ROE.

Mr. Gorman's focus on interest rates ignores the undisputed increase in utility dividend yields.[107] AWEC acknowledges the historically high utility sector stock prices.[108] Yet, Mr. Gorman accounts for this fact only in his CAPM analysis, where he acknowledges that current market conditions have "artificially lowered the beta estimate for utility stocks[.]"[109] He does not consider that the same market conditions have "artificially" decreased the dividend yield in the DCF model, which is why it is currently understating equity costs.[110] Mr. Gorman also ties the "artificially" lower betas to his claim that utility stocks acted as a safe haven during the early stages of the pandemic.[111] Because betas have now increased, however, Mr. Gorman's reasoning suggests that utility stock are no longer safe haven investments, as discussed above. PacifiCorp conservatively estimated that updating Mr. Gorman's DCF modeling using the same rationale he applies to his CAPM results increases his results by 47 bps for an ROE estimate of 9.7 percent.[112]

7. AWEC's Risk Premium models understate PacifiCorp's ROE by improperly relying on data from different time periods.

It is well established in both academic literature and real world data that there is an

[106] PAC/3500, Bulkley/7.
[107] PAC/2200, Bulkley/82-83.
[108] AWEC/200, Gorman/55.
[109] AWEC/200, Gorman/55.
[110] PAC/2200, Bulkley/79-81
[111] AWEC/200, Gorman/55.
[112] PAC/2200, Bulkley/85.

inverse relationship between interest rates and equity risk premiums—as interest rates decrease, equity risk premiums increase.[113] Mr. Gorman's Risk Premium models, however, ignore this fact and instead mismatch historical risk premiums with projected bond yields. By combining historical and projected data, Mr. Gorman understates his results by ignoring the inverse relationship between equity risk premiums and interest rates—a relationship that Duff & Phelps explained in Mr. Gorman's own workpapers (discussed above). Using the same period for both the bond yields and risk premium increases Mr. Gorman's results to a range of 9.58 percent to 10.05 percent.[114]

8. Staff's adjustments to its ROE models unreasonably depress the results.

a. <u>Staff's adjusted long-term growth rates call into question its Multi-Stage DCF results.</u>

Staff's rebuttal testimony describes in depth how the pandemic increased equity market volatility, increased equity risk premiums (evidenced by higher beta coefficients), and decreased utility stock prices.[115] Each of these conditions should increase PacifiCorp's cost of equity. Yet, when Staff updated its DCF modeling, the results increased slightly, but Staff's recommended ROE remained unchanged at 9.0 percent.[116] This result appears driven by Staff's exclusive reliance on the Multi-Stage DCF results coupled with Staff's adjustment to the long-term growth rates used in that model.

Staff acknowledged at hearing that the dividend yield component of the DCF model increased in its rebuttal testimony because of lower stock prices.[117] Then, to offset the higher dividend yields, Staff decreased the model's long-term growth rates. But Staff's testimony explicitly states that there were no updated long-term growth rates available—a fact that is

[113] PAC/2200, Bulkley/100-106.
[114] PAC/2200, Bulkley/108
[115] Staff/1900, Muldoon-Enright-Dlouhy/99.
[116] Staff/205; Staff/1904.
[117] Sept. 9, 2020, Tr. 68:8-69:24.

confirmed by Staff's exhibits, which show that the sources of its long-term growth rates were not updated after Staff filed its opening testimony.[118] At hearing, Staff was unable to reconcile its testimony on the unavailability of updated long-term growth rates with the fact that Staff decreased the long-term growth rates in the model.[119] Staff's updated Multi-Stage DCF model also introduced a new and markedly lower long-term growth forecast without explanation, which was particularly troubling because the forecast was available long before Staff filed its opening testimony.[120]

Staff's initial results using its questionable long-term growth rates produced no ROE estimate higher than 8.80 percent, which is 20 bps less than Staff's recommended ROE and 90 bps less than national averages.[121] The only long-term growth rate Staff used that produces reasonable results was PacifiCorp's long-term growth rate based on historical Gross Domestic Product (GDP) growth.[122] But Staff's updated testimony also adjusted PacifiCorp's growth rate downward—again, without explanation. Had Staff simply used the correct PacifiCorp long-term growth rate, the upper end of its reasonable ROE range would have increased to 9.82 percent.[123]

Comparing Staff's Multi-Stage DCF results to its Constant Stage DCF results further undermines the credibility of Staff's adjusted long-term growth rates. Staff's updated Constant Stage DCF results, which did not use the same adjusted growth rates, increased by 60 bps and produced an average ROE of 9.5 percent.[124] Moreover, the median of Staff's Constant Growth

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[118] Staff/1900, Muldoon-Enright-Dlouhy/96 (Staff "reviewed each of its sources, to ensure that the most recent growth rates are being reflected in this testimony" and "at this time no updated long-run growth rates are available which reflect COVID-19 scenarios."); Staff/1907 (confirming no updated long-term estimates).
[119] Sept. 9, 2020, Tr. 78:2-19.
[120] Sept. 9, 2020, Tr. 79:6-15.
[121] PAC/2200, Bulkley/53.
[122] PAC/2200, Bulkley/53-54.
[123] PAC/3500, Bulkley/3.
[124] Sept. 9, 2020, Tr. 80:10-24.

DCF results was 9.8 percent[125] and Staff testified that, "considering the median value ensures that neither overly high nor overly low estimated required returns get factored into the presented statistic."[126] Had Staff excluded results that were less than 8 percent, as it did in its updated CAPM, the average ROE would be 10.12 percent.[127]

b. Staff's updated CAPM decreased the market risk premium to offset the impact of higher beta coefficients.

Staff's initial CAPM results used a market risk premium of 10.32 percent and produced a mean ROE of 7.7 percent.[128] In rebuttal testimony, Staff acknowledged that its beta coefficients increased and claimed that Staff also increased the market risk premium input from 6 percent to 8.18 percent, which reflected Staff's understanding that equity costs were increasing.[129] Staff's actual modeling, however, *reduced* the market risk premium from 10.32 percent to 8.18 percent, which offset the impact of higher beta coefficients.[130] Thus, Staff's testimony contradicted its modeling and described increased equity costs resulting from a higher market risk premium, while Staff's modeling decreased equity costs through a lower market risk premium. Had Staff not reduced the market risk premium by over 200 bps, Staff's updated CAPM results would have been significantly higher than 9.3 percent. As of PacifiCorp's reply testimony (which only had partially updated beta coefficients), updating only Staff's beta coefficients produced a CAPM result of 10.15 percent, which is 85 bps higher than Staff's updated CAPM with the lower market risk premiums.[131]

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[125] Staff/1906.
[126] Staff/1900, Muldoon-Enright-Dlouhy/72.
[127] PAC/3500, Bulkley/4.
[128] Staff/206.
[129] Staff/1900, Muldoon-Enright-Dlouhy/103 ("instead of using Morningstar's long-run market risk premium of 6 percent, Staff instead calculated the market risk premium using the 30-year average market return on the S&P 500.").
[130] Staff/206; Staff/1905.
[131] PAC/2200, Bulkley/65; Staff/1905.

9. AWEC's criticism of PacifiCorp's modeling misses the mark.

AWEC criticizes PacifiCorp for excluding DCF results below 7.0 percent from Ms. Bulkley's reported results.[132] Ms. Bulkley's removal of outlier data is reasonable; Staff also removed results less than 8.0 percent from its CAPM results and Mr. Gorman implicitly agrees that ROE estimates below 7.0 percent are unreasonable.[133]

AWEC claims that the long-term growth rate used in PacifiCorp's Multi-Stage DCF analysis was "not drawn from consensus market expectations" but is simply a "personal forecast."[134] This is untrue. Ms. Bulkley's long-term growth rate was based on real historical GDP growth from 1929 through 2018, calculated using data from the U.S. Department of Commerce's Bureau of Economic Analysis.[135] Ms. Bulkley used a projected inflation rate based on forecasts from Blue Chip Financial Forecasts and the Energy Information Administration.[136] Ms. Bulkley's use of historical real GDP growth is consistent with the approach taken by Morningstar, a leading provider of investment information, because real GDP growth has been "reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term future performance."[137] Moreover, the long-term growth rate that Ms. Bulkley relied on in her Multi-Stage DCF analysis was 5.56 percent,[138] which is well below the 9.10 percent growth rate that is implied by the market return estimate used by Mr. Gorman in his own CAPM analysis.[139] The growth rate that is implied in Mr. Gorman's Market Risk Premium is more than twice the long-term nominal GDP growth rate he uses in his Multi-Stage DCF model.[140]

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[132] AWEC Prehearing Brief at 4.
[133] PAC/2200, Bulkley/73-74; PAC/3500, Bulkley/4.
[134] AWEC Prehearing Brief at 4.
[135] PAC/400, Bulkley/48.
[136] PAC/400, Bulkley/48.
[137] PAC/2200, Bulkley/53-54.
[138] PAC/2203, Bulkley/1.
[139] PAC/2200, Bulkley/89-91.
[140] PAC/2200/Bulkley/91.

AWEC also criticizes the long-term growth rates used to derive the market risk premium in Ms. Bulkley's CAPM analysis.[141] But Ms. Bulkley's market risk premiums are comparable to those used by Mr. Gorman.[142] In addition, AWEC claims that PacifiCorp's Risk Premium results improperly rely on projected treasury bond yields from Blue Chip.[143] AWEC cannot dispute, however, that investors rely on market projections from reputable firms like Blue Chip when estimating returns. Indeed, Mr. Gorman relies on Blue Chip for projected inflation, GDP growth, the risk-free rate for his CAPM, and interest rates.[144]

AWEC also rejects Ms. Bulkley's Expected Earnings and ECAPM as "simply unaccepted methods of estimating a reasonable ROE for regulated utilities."[145] To the contrary, RRA—an authority Mr. Gorman cites extensively—has been clear: "Many commissions consider the results of a comparable earnings analysis when establishing an authorized ROE."[146] Similarly, the academic literature cited by Mr. Gorman provides empirical support for the use of the ECAPM, which is consistent with other studies that have reached similar conclusions.[147]

III. ANNUAL POWER COST ADJUSTMENT

A. <u>The Commission should approve the Annual Power Cost Adjustment to allow fair recovery of prudently incurred NPC and to properly align regulatory incentives with Oregon's energy policy.</u>

The proposed Annual Power Cost Adjustment (APCA) provides PacifiCorp with a mechanism that allows for the recovery of NPC in a manner that properly aligns the regulatory structure to reflect the significant changes that have occurred over the past decade in Northwest power production and supply. The APCA would replace the Company's TAM and Power Cost

[141] AWEC Prehearing Brief at 5.
[142] PAC/2200, Bulkley/91 (Mr. Gorman used 11.08 percent, Ms. Bulkley used 12.12 percent and 12.01 percent).
[143] AWEC Prehearing Brief at 5.
[144] AWEC/200, Gorman/14-15, 56, 69; AWEC/219.
[145] AWEC Prehearing Brief at 7.
[146] Staff/1911, Muldoon-Enright-Dlouhy/303; *see also* Morin at 428; Hahne at 9-11.
[147] PAC/2200, Bulkley/94-97.

Adjustment Mechanism (PCAM). Under the APCA, PacifiCorp would annually file an NPC forecast for the following year, along with a true-up for the actual, prudent power costs of the previous year. Significantly, the APCA would not include deadbands, sharing bands, or earnings tests, but parties would have the opportunity to review to ensure only prudently incurred costs are included for recovery.[148]

The PCAM is premised on a series of assumptions that are not well suited for NPC recovery and not consistent with "the many complex policy initiatives that Oregon is pursuing or considering for the upcoming several years."[149] One of these assumptions is that under- and over-collections will "balance out over time."[150] Yet despite years of persistent and significant under-recovery of prudently incurred costs, PacifiCorp has never triggered a rate change through the PCAM.[151] Over the past twelve years, PacifiCorp has under-recovered approximately $282 million in Oregon NPC, with only a single year of slight off-setting recovery in 2016.[152]

The Commission adopted the PCAM in 2012, based on a model developed for Portland General Electric Company (PGE) between 2005-2008. Since that time, Oregon energy policy has changed dramatically, as have the regional markets in which PacifiCorp operates. Renewable energy comprises a growing share of the Western energy market and PacifiCorp's portfolio. Changes in weather and the inherent variability of many renewable energy resources mean that the Company faces increased system balancing transactions and continued NPC under-recovery.[153] These resources save money for the system, but their costs are intrinsically under-

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[148] PAC/500, Wilding/9-10; PAC/2000, Wilding/70.
[149] PAC/3000, Graves/4.
[150] *In the Matter of Portland General Electric Company and PacifiCorp, dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket UM 1662, Order No. 15-408 at 7 (Dec. 8, 2015).
[151] PAC/500, Wilding/2.
[152] PacifiCorp accounts for certain unusual 2016 Jim Bridger coal costs that would not be included in a TAM. PAC/500, Wilding/5.
[153] PAC/2000, Wilding/52.

forecasted and uncontrollable—and hence, under-recovered—despite being unchallenged as prudently incurred costs.[154]

The APCA removes the unintended disincentive to increase renewable generation procurement that now exists in the PCAM—even though these resources tend to reduce average net power costs.[155] Because the causes of the Company's under-recovery are impossible to either forecast or control, the true incentive of the PCAM's current risk-bearing provisions is to encourage utilities to identify highly *predictable* generation sources that allow actual NPC to align with forecast NPC—*i.e.*, to pursue less dynamic resource plans and operational activities.[156]

Rather than conforming to the PCAM's incentive to identify highly predictable generation, PacifiCorp has pursued innovative means of lowering overall NPC for its customers, both through increased reliance on renewable generation, and through the creation and reliance on the Energy Imbalance Market and market transactions.[157] Under the PCAM, PacifiCorp is penalized for these efforts to lower overall NPC because the reduced costs of renewable energy and market transactions also carry increased variability and unpredictability.[158] Under the APCA, PacifiCorp would still have the incentive to manage its system prudently and efficiently, but the APCA's incentives would be resource neutral and consistent with the sphere of PacifiCorp's actual control.

Reforming the PCAM to incent more investment in renewable energy advances the Governor of Oregon's recent executive order urging this Commission to take action to promote

[154] PAC/600, Graves/47.
[155] PAC/3700, Graves/4-5.
[156] PAC/3700, Graves/5.
[157] PAC/3600, Wilding/6-7.
[158] PAC/600, Graves/36.

reduced greenhouse gas (GHG) emissions. In Executive Order 20-04 (EO 20-04), the Governor directed the Commission to exercise "any and all authority and discretion" to facilitate GHG-reduction goals.[159] Approving the APCA would facilitate GHG-reduction goals by making the continued pursuit of renewable energy investments truly cost neutral for PacifiCorp, as contemplated by the legislature in ORS 469A.120(1).

1. PacifiCorp must have a fair opportunity to recover prudently incurred costs of providing service.

CUB argues that PacifiCorp's persistent under-recovery of prudently incurred NPC is "a non-issue" because the Company "has consistently been earning a reasonable ROE."[160] CUB's position ignores a central tenet of the regulatory compact, whereby a regulated utility must be "allowed the opportunity to recover its prudently incurred costs[.]"[161] Systematic under-recovery is incompatible with this state's cost-of-service paradigm for regulated utility service.

AWEC claims that increasing renewable penetration does not correspond to increasing under-recovery because PacifiCorp's NPC forecasts have become more accurate in recent years.[162] This statement is incomplete because it misunderstands that the increasing share of intermittent renewables has made forecasting errors worse for balancing costs, even if there have been some improvements in long-term average cost predictions.[163] Moreover, the forecasting discrepancies in recent years include only about half of the Company's 4,789 MW of new renewables—meaning that substantial increases in forecasting discrepancies are yet to come.[164]

CUB and Small Business Utility Advocates (SBUA) also argue that, even if the APCA

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[159] Oregon Executive Order No. 20-04 at 5 (March 10, 2020) (hereafter "EO 20-04").
[160] CUB's Prehearing Brief at 10.
[161] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket UE 115, Order No. 01-988 at 6 (Nov. 20, 2001).
[162] AWEC's Prehearing Brief at 21.
[163] PAC/3700, Graves/22.
[164] PAC/3700, Graves/22-23.

has merit, the Commission should deny PacifiCorp's proposal to fully and fairly recover its costs because of the broader economic circumstances.[165] According to these parties, PacifiCorp should "just settle for somewhat low returns that are close enough" and forego recovery of prudently incurred costs.[166] The Commission has previously disavowed the notion that broader economic circumstances can void the regulatory compact and deny a utility the opportunity to recover prudently incurred costs.[167] As the Commission explained, economic circumstances and the need to avoid customer rate shock constitute "a relevant factor in the rate design stage of the case" but "play[] no role in determining a utility's revenue requirement."[168]

2. The APCA is consistent with the Commission's policies that seek to avoid persistent under-recovery.

Staff, AWEC, and CUB claim that the APCA is inappropriate because the Commission's PCAM policies anticipate "normal business risk" in the form of hydro variability, and PacifiCorp's under-recovery simply reflects the costs of system balancing transactions.[169] While the Commission's policies anticipate some degree of variability, they do not anticipate long-term and persistent under-recovery. Normal business risk should balance out over time, but this NPC shortfall situation does not and will not do so; it is one-sided, favoring losses.[170] The Commission's Order No. 15-408 clearly states that remedial steps are appropriate "[i]n the event of a persistent forecast error in one direction[.]"[171] While the Commission expressed a preference for resolving under-recovery through modeling improvements where possible, the Commission

[165] SBUA Prehearing Brief at 7; CUB/400, Jenks/2-4.
[166] SBUA Prehearing Brief at 7 (internal quotation marks omitted).
[167] Order No. 01-988 at 6.
[168] Order No. 01-988 at 6.
[169] Staff's Prehearing Brief at 30 (quoting *In re Portland General Electric*, Dockets UE 180, UE 181 & UE 184, Order No. 07-015 at 26 (Jan. 12, 2007)); AWEC's Prehearing Brief at 18.
[170] PAC/3700, Graves/9.
[171] Order No. 15-408 at 7.

was equally clear that the PCAM was not intended to systematically disallow prudent costs.[172]

3. PacifiCorp's persistent under-recovery cannot be solved through modeling improvements.

Staff, CUB, and AWEC argue that the Company "has failed to demonstrate that it is unable to make modeling changes" to address the persistent under-recovery of power costs.[173] However, no amount of modeling improvements can solve the discrepancy between a dispatch model's perfectly efficient operation and the actual variability of intermittent generation in a complex market environment, which occurs in reaction to new, mid-year information on shifting market conditions that could not have been known in advance.[174] This mismatch is an inevitable part of the Company's optimized modeling approach, where forecasts cannot account for the increased costs associated with accommodating actual generation and system balancing needs. These gaps arise within the TAM's one-year forecast horizon, which does not track shorter-term variances.[175]

AWEC claims that the Company's forecasting and system balancing concerns have already been resolved through the Day-Ahead/Real-Time (DA/RT) adjustment.[176] While the DA/RT has helped to mitigate the Company's persistent under-recovery, it has clearly not closed the gap between forecast and actual NPC. Additionally, given the opposition of AWEC and other parties to modeling changes in the TAM, it is unrealistic to assume that problems inherent in the forecasting process can be solved through increasingly complex modeling adjustments.[177]

Staff suggests that PacifiCorp's anticipated switch to the AURORA forecasting model

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[172] Order No. 15-408 at 7.
[173] Staff's Prehearing Brief at 31; *see also* AWEC's Prehearing Brief at 18; CUB's Prehearing Brief at 10-11.
[174] PAC/3600, Wilding/5.
[175] PAC/3000, Graves/18.
[176] AWEC's Prehearing Brief at 18.
[177] PAC/3600, Wildling/5.

could mitigate the under-recovery issue.[178] However, the version of AURORA that the Company is implementing is similar to the current Generation and Regulation Initiative Decision Tools (GRID) in that it does not, on its own, capture the inherent uncertainty that exists in forecasting NPC.[179] Given that NPC dispatch models balance load and generation with perfect foresight, they cannot account for hourly deviations in actual generation and dispatch conditions.[180]

4. PacifiCorp's under-recovery experience is not analogous to other utilities.

AWEC argues that the APCA should be rejected because PacifiCorp's under-recovery is tied to economic and industry changes applicable to all utilities, yet PacifiCorp appears to be the only utility being negatively impacted.[181] PacifiCorp's experience is not comparable to other Oregon utilities. Idaho Power uses a version of modeling that relies on a traditional heuristic approach, as compared to PacifiCorp's optimization model.[182] Moreover, neither PGE nor Avista Corporation have comparable levels of intermittent renewable resources, while both have significantly greater access to flexible, load-following resources. Thus, while PacifiCorp has effectively managed its larger, more complex system operations to customers' benefit through increased renewable penetration and access to low-cost market transactions, these actions have increased the *variability* of the Company's power costs—resulting in systematic under-recovery. The TAM and the PCAM do not fairly and accurately capture these complexities in rates.[183]

5. The PCAM's risk-sharing incentives are counterproductive.

Staff, CUB, and AWEC argue that removing deadbands, sharing bands, and earnings tests will remove the Company's incentive to control NPC.[184] However, this argument

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[178] Staff's Prehearing Brief at 31-32.
[179] PAC/3600, Wildling/13-14.
[180] PAC/2000, Wildling/65.
[181] AWEC's Prehearing Brief at 19-20.
[182] PAC/3600, Wilding/13-14.
[183] PAC/2000, Wildling/72-73.
[184] Staff's Prehearing Brief at 33-34; CUB's Prehearing Brief at 11; AWEC's Prehearing Brief at 18.

incorrectly assumes that the current PCAM provides genuine cost-control incentives—that is, that the structure incents the Company to operate more efficiently.[185] This fundamentally misunderstands how PacifiCorp operates. "PacifiCorp does not operate its system to meet its ratemaking structures"; rather, the opposite should be true: those ratemaking structures should reflect how PacifiCorp actually operates.[186] As noted above, one of the primary advantages of the APCA is that its incentives are aligned with continued acquisition of energy from renewable resources and encouraging innovation in the development of regional electric markets. This is unlike the current PCAM, which incents non-intermittent power sources and overly traditional power supply strategies, even if these are not lowest cost for customers.

6. The APCA is consistent with the 2020 TAM stipulation.

Staff has taken the position that PacifiCorp must adjust actual annual wind generation to match the forecast annual wind generation as a result of the 2020 TAM stipulation.[187] However, this position is inconsistent with the language and spirit of the 2020 TAM stipulation. The stipulation specifically states that PacifiCorp agrees to use certain "wind capacity factors for its owned wind facilities in its TAM *forecasts*."[188] The 2020 stipulation requires the Company to use stipulated capacity factors for the NPC forecast, but Mr. Wilding notes that "actual NPC will continue to be affected by the actual wind generation and will be reflected in the APCA just as it would have been reflected in the PCAM."[189] The 2020 TAM stipulation does not restrict the Commission's ability to authorize a true-up of actual net power costs through the PCAM, the

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185 PAC/3600, Wilding/10.
186 PAC/2000, Wilding/70.
187 Staff/2400, Gibbens/16 (Staff claims that the APCA "would not hold itself to the P50 forecast for the actual power generated.").
188 *In the Matter of PacifiCorp d/b/a Pacific Power 2020 Transition Adjustment Mechanism*, Docket UE 356, Order No. 19-351 at Appendix A, ¶18 (Oct. 30, 2019) (emphasis added).
189 PAC/2000, Wilding/69.

APCA, or other power cost adjustment mechanism.[190] The benefits of the Energy Vision (EV) 2020 projects were the PTCs and the zero-fuel cost energy, which reduce NPC.[191] Under the APCA, customers will receive those benefits, consistent with the 2020 TAM Stipulation.[192]

B. The Commission should approve PacifiCorp's minor changes to the NPC guidelines.

PacifiCorp requests that the Commission approve updated NPC guidelines to allow smooth implementation of the APCA.[193] If the Commission approves the APCA, parties largely do not oppose PacifiCorp's proposed guidelines, with the exception of two issues.[194]

1. PacifiCorp has agreed to provide NPC workpapers in a timely manner.

PacifiCorp has proposed to provide workpapers consistent with the current TAM guidelines. Under these guidelines, the Company provides some workpapers at the time of filing, another set five days later, and the balance of materials within 15 days.[195] In the Company's most recent two TAMs, PacifiCorp provided all of the GRID model data inputs in the five-day workpaper submission.[196]

AWEC argues that PacifiCorp should be required to file all workpapers for the NPC forecast concurrently with the initial filing, with the exception of four NPC sample calculations for Schedule 294.[197] AWEC's proposal is unnecessary and unworkable. PacifiCorp already provides a substantial volume of information—including all GRID inputs—concurrent with filing, which allows parties to begin reviewing the basis for the Company's filing immediately. Moreover, given the complexity of the filing, it would be significantly burdensome for the

[190] UE 356 – Stipulation at 8-9.
[191] PAC/3600, Wilding/14-15.
[192] UE 356 – Stipulation at 8.
[193] PAC/3602.
[194] Staff's Prehearing Brief at 36; AWEC/500, Kaufman/42-43 (accepting all changes except for the timing for filing workpapers).
[195] PAC/3600, Wildling/19-20.
[196] PAC/3600, Wildling/20.
[197] AWEC's Prehearing Brief at 46.

Company to process more workpapers on the same day as the initial filing.[198]

2. Wheeling revenues are appropriately included in base rates because they offset transmission costs.

Wheeling revenues are used to offset the Company's transmission costs in the revenue requirement calculation. This approach matches the Company's cost to construct transmission with the corresponding revenues created by those investments. CUB proposes to move wheeling revenues from base rates to the NPC recovery mechanism—either the TAM or the APCA, if approved.[199] CUB argues that this approach is appropriate because NPC already include wheeling *costs*. This analysis incorrectly implies that CUB's adjustment is based on the matching principle. To be clear, wheeling costs are necessary to obtain power over non-PacifiCorp transmission systems, and are thus tied to variable NPC.[200] Wheeling revenues, in contrast, are associated with the capital investment in PacifiCorp's transmission system—the cost of which is included in base rates.[201] Therefore, wheeling revenues are appropriately included in base rates to offset the Company's own transmission system costs.

IV. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT COST RECOVERY MECHANISM

A. The proposed Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism balances baseline cost recovery and performance incentives.

PacifiCorp and Staff propose instituting a Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism (Wildfire Recovery Mechanism) to recover costs related to wildfire mitigation and vegetation management.[202] The degree and variability of wildfire risk is increasing across the West, leading PacifiCorp to develop a capital intensive

[198] PAC/3600, Wildling/19.
[199] CUB's Prehearing Brief at 15-16.
[200] PAC/2000, Wilding/74.
[201] PAC/3600, Wilding/21.
[202] PAC/200, Lockey/23; Staff's Prehearing Brief at 7.

wildfire mitigation plan, in addition to the Company's routine safety and maintenance program.[203] The Company has included its 2020 capital expenditures and its 2021 operations and maintenance (O&M) costs in base rates, with the Wildfire Recovery Mechanism applying to recovery of incremental expenditures in 2021 and beyond.[204] The proposed mechanism is consistent with the Governor's EO No. 20-04, which directs the Commission to "promote energy system resilience in the face of increased wildfire frequency and severity[.]"[205]

While Staff and PacifiCorp agree on the general contours of the Wildfire Recovery Mechanism—including application of performance metrics and a modulated earnings test, use of an independent evaluator (IE) to evaluate the Company's costs, and the timing of the Company's annual filing—Staff has raised three remaining implementation concerns.

First, Staff proposes to apply performance metrics and an earnings test to $6.645 million of PacifiCorp's baseline expenses.[206] Staff would then apply a separate set of earnings tests and performance metrics for costs incurred in excess of the Company's total $33.225 million Test Year expenses.[207] Staff asserts that the Company would still have the opportunity to recover these costs "if prudently incurred." PacifiCorp disagrees because, despite the Company's clear demonstration of prudence in this case, application of the earnings test could prevent full recovery of these prudently incurred and essential costs.[208] The Company's $33.225 million recovery request establishes an appropriate cost baseline for the new mechanism, reflecting a realistic, near-term forecast of costs that were last updated seven years ago. PacifiCorp proposes that the performance metrics apply to the first $6.645 million of *incremental* costs over the

[203] PAC/200, Lockey/23.
[204] PAC/200, Lockey/25.
[205] EO 20-04 at 8.
[206] Staff's Prehearing Brief at 7-8.
[207] Staff's Prehearing Brief at 8.
[208] Staff's Prehearing Brief at 9 ("Expenses found to be prudently incurred in a year, but nevertheless not amortized into rates due to the applications of an earnings test, would not roll-over for cost recovery in a future year.").

Company's baseline expenses.[209] The Company's approach would also void the need for Staff's more complex review process.

Second, Staff objects to waiting for resolution of the wildfire rulemaking proceeding before establishing the criteria, scope, budget, and selection of an IE, given the time still required to complete that proceeding.[210] Staff therefore proposes that an IE be established prior to the Commission issuing final rules in the wildfire rulemaking, with the understanding that PacifiCorp's use of the IE could be revisited at a later date.[211] PacifiCorp agrees to work with Staff to develop the appropriate scope for the IE pending completion of the Commission's wildfire rulemaking process, so long as the scope and metrics used by the IE are revisited as the rulemaking advances.

Third, Staff questions the Company's approach to normalizing violations on a per-audit-mile basis, and specifically whether the Company's proposal might allow greater cost recovery despite lack of improvement in vegetation management performance.[212] As PacifiCorp explained at hearing, the Company's approach would result in more effective performance incentives by tying recovery to reductions in the *rate* of vegetation management violations, rather than to specific numbers of total violations.[213] In contrast, Staff's flat violation rate does not consider the amount of the Company's system audited in a given year. For example, if Staff audited 20 percent of PacifiCorp's system in Year 1 and found 4 violations, and then audited 40 percent of PacifiCorp's system in year 2 and found 6 violations, Staff's approach (relying on the total number of violations) would assume that the Company's performance in Year 2 had deteriorated

[209] PacifiCorp's Prehearing Brief at 26-27.
[210] Staff's Prehearing Brief at 11.
[211] Staff's Prehearing Brief at 11.
[212] Staff's Prehearing Brief at 10.
[213] Sept. 9, 2020, Tr. 145:22-146:19.

by 50 percent, even though PacifiCorp would have successfully reduced the violation *rate* by 25 percent.

Here, PacifiCorp proposed the following violation (or error) rates: 0.3 percent for level 3, 0.24 percent for level 2, and 0.15 percent for level 1—each calculated as vegetation management violations per 14,359 overhead miles.[214] These specific rates are both reasonably achievable and represent meaningful reductions in the violation rate, directly incenting PacifiCorp to reduce its violation rate to pre-2013 levels as Staff proposes.

AWEC opposes the Wildfire Recovery Mechanism on the basis that the costs are foreseeable, minimal harm would inure to the Company, traditional ratemaking treatment should be favored, and costs of mitigating wildfire risk should be shared with shareholders.[215] But the fact that wildfire costs are, to an extent, foreseeable does not mean that the Wildfire Recovery Mechanism is inappropriate. These are dynamic and substantial costs necessary to ensure the safety of the Company's system. PacifiCorp's investments would remain subject to a prudence review, with performance incentives to support improvements to vegetation management.

AWEC also argues that the Wildfire Recovery Mechanism is inappropriate because it fails to meet the requirements for deferred accounting under ORS 757.259(2)(e), in part because the mechanism causes more frequent (annual) rate changes.[216] PacifiCorp disagrees that the proposed mechanism is subject to ORS 757.259(2)(e) because the mechanism is an automatic adjustment clause separately authorized by statute under ORS 757.210(1). Nonetheless, the mechanism meets the statutory requirements for deferral under ORS 757.259(2)(e) because it concerns "[i]dentifiable utility expenses or revenues," will "minimize the frequency of rate

[214] PAC/3300, Lockey/36.
[215] AWEC/500, Kaufman/32, 34.
[216] AWEC's Prehearing Brief at 29.

changes" by avoiding more frequent rate cases, and will "match appropriately the costs borne by and benefits received by ratepayers."[217]

Finally, AWEC further argues that, if the Wildfire Recovery Mechanism is approved, any earnings test should be capped at 100 basis points below PacifiCorp's authorized return.[218] However, as explained by both Staff witness Mr. Mitchell Moore and PacifiCorp witness Ms. Etta Lockey, modulated earnings tests more appropriately balance the interests of customers and shareholders while also serving the public interest in helping to prevent wildfires.[219]

V. EMISSIONS CONTROL INVESTMENTS

To comply with regional haze requirements, PacifiCorp made prudent and necessary decisions to install selective catalytic reduction systems (SCRs) at Jim Bridger Units 3 and 4, Hayden Units 1 and 2, and Craig Unit 2, and baghouse and low nitrogen oxide (NOx) burner (LNB) technologies at Hunter Unit 1.[220] In Order No. 12-493 in docket UE 246,[221] the Commission addressed an earlier set of emissions control investments and found that PacifiCorp "was required to take action to comply with the mandate" of the regional haze rule, and that the Company acted prudently in initiating such compliance efforts. The Commission also confirmed that the prudence of emissions control investments "is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness."[222]

The Commission should allow recovery of these investments, each of which mitigate

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[217] ORS 757.259(2)(e).
[218] AWEC's Prehearing Brief at 29.
[219] Staff/2700, Moore/11-15; PAC/3300, Lockey/38.
[220] PAC/3800, Link/3; PAC/2600, Ralston/34; PAC/2300, Link/47.
[221] *In the Matter of PacifiCorp, dba Pacific Power, Request for General Rate Revision*, Docket UE 246, Order No. 12-493 at 31 (Dec. 20, 2012) (reviewing whether PacifiCorp prudently decided to invest in emissions control investments at seven coal units, in advance of pending environmental compliance obligations).
[222] *Id.* at 25 (citations omitted).

emissions and ensure compliance with clean-air regulations. PacifiCorp based its investment decisions on a review of alternative courses of action and robust cost-effectiveness analyses; the investment decisions pre-date by several years the passage of Senate Bill 1547 in 2016, requiring removal of coal plants from Oregon rates, and the approval of the 2020 Inter-Jurisdictional Cost Allocation Protocol (2020 Protocol) with provisions for coal plant Exit Orders; and Oregon customers have already received the benefits of the investments in NPC for many years at no cost, due to the Company's long rate case stay-out.[223]

CUB, AWEC, and Sierra Club challenge the prudence of the Company's SCR investments at the Jim Bridger plant,[224] and Staff proposes a partial disallowance tied to the perceived rigor of the Company's economic analysis.[225] For the Hayden and Hunter plants, Sierra Club and AWEC, respectively, challenge the prudence of the Company's investments.[226] No party challenges the prudence of the Company's SCR investment at Craig. However, Staff (and, to a lesser extent, CUB) contest the Company's calculation of depreciation for each of these emission control investments.[227]

A. PacifiCorp prudently installed SCRs at Jim Bridger Units 3 and 4 because SCRs were the best compliance option for customers.

The regional haze rule is implemented through state implementation plans (SIPs), which include site-specific emissions control requirements. Wyoming's SIP required installation of SCRs at Jim Bridger Units 3 and 4 by 2015 and 2016, respectively.[228] The Company knew that it would take roughly two-and-one-half years to install the SCRs, meaning that it had to execute an engineering, procurement, and construction (EPC) contract by no later than mid-2013 to meet the

[223] *See* PAC/800, Teply/10.
[224] CUB's Prehearing Brief at 12; AWEC's Prehearing Brief at 33; Sierra Club's Prehearing Brief at 3.
[225] Staff's Prehearing Brief at 36.
[226] Sierra Club's Prehearing Brief at 26; AWEC's Prehearing Brief at 35.
[227] Staff's Prehearing Brief at 39; CUB's Prehearing Brief at 14.
[228] PAC/2506, Owen/8 (Excerpt from June 10, 2013 Federal Register).

2015 compliance deadline at Jim Bridger Unit 3.[229] This schedule also allowed PacifiCorp to install the SCRs during major maintenance outages, reducing compliance costs.[230]

In May 2013—after five years of litigation and negotiations with environmental regulators and more than a year of state regulatory proceedings[231]—PacifiCorp moved forward with the decision to install SCRs at Jim Bridger Units 3 and 4 because it was the most cost-effective compliance option and because the Company was legally required to do so. PacifiCorp reviewed and confirmed this decision just before issuing the full notice to proceed (FNTP) and starting construction in December 2013. At the time, the 2,100 MW Jim Bridger plant was an integral resource for PacifiCorp, representing approximately 20 percent of baseload capacity and providing critical ancillary services such as voltage regulation, frequency regulation and response, energy imbalance correction, and operating reserves.

1. ***PacifiCorp conducted extensive economic analysis to identify the best available compliance option for customers before executing the EPC in May 2013.***

In 2012, the Company developed its initial economic analysis of compliance options. Using its System Optimizer (SO) Model—the same modeling 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.[232] While the Company's economic analysis focused on the base case present value revenue requirement differential (PVRR(d)) for each option,[233] the Company also used high and low gas curves and carbon prices for a total of nine different scenarios.[234] The analysis showed that the SCRs were the most cost-effective compliance option by several hundred million dollars, with gas conversion a distant second

[229] PAC/2300, Link/14.
[230] PAC/800, Teply/34.
[231] PAC/800, Teply/30-32.
[232] PAC/700, Link/89-90.
[233] PAC/700, Link/43.
[234] PAC/700, Link/90-98.

place.[235] The Company's 2012 analysis was used to support fully litigated pre-approval cases in Wyoming and Utah.[236]

In February 2013, the Company comprehensively updated its 2012 analysis using its January 2013 long-term fueling plan for the Jim Bridger plant.[237] The updated results continued to decisively favor the SCRs, this time by $183 million.[238] Because natural gas and carbon prices are the primary drivers in the economics of the SCRs, the Company developed a breakeven price for each using the SO model.[239] This analysis used precise regressions that allowed the Company to continuously monitor market changes after executing the EPC contract, without having to re-create its analysis for changes in these factors.[240]

In May of 2013, the Wyoming and Utah Public Service Commissions (PSCs) both approved the SCRs, concluding that SCRs were "the most preferable option,"[241] and that there was "no compelling evidence, arguments, or analysis shifting the economics to favor an alternative strategy to comply with the Wyoming SIP requirements."[242] Sierra Club participated in both cases, raising many of the same issues it now raises in this case.[243] Since that time, Sierra Club has also challenged the Jim Bridger SCRs in Washington, where the Washington

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[235] PAC/700, Link/110.
[236] Wyoming PSC, *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013); Utah PSC, *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).
[237] PAC/2300, Link/6.
[238] PAC/2300, Link/6.
[239] PAC/700, Link/101.
[240] PAC/700, Link/101.
[241] Wyoming PSC, *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013).
[242] *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).
[243] Wyoming PSC, *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Sierra Club's Post-Hearing Legal Brief (Apr. 8, 2013); Utah PSC, *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, Sierra Club Post-Hearing Brief Addressing EPA Ruling (Apr. 5, 2013).

Commission rejected Sierra Club's analysis and approved partial cost recovery, and in the Company's 2019 California rate case, where the California Public Utility Commission (California Commission) concluded that the Company's SCR investments were reasonable and necessary, and approved full cost recovery.[244] As a result, the Jim Bridger SCR investments are now in PacifiCorp's rates in four of PacifiCorp's six states, and the fifth state, Idaho, approved the SCR investment for Jim Bridger co-owner Idaho Power in December 2013.[245] The Idaho Public Utility Commission found that the Jim Bridger plant "is a source of low-cost and dispatchable baseload energy that provides reliable capacity during peak customer demand" and that the plant is "critical to the reliable operation of the high voltage transmission system."[246]

2. The Commission's 2013 IRP decision deferred a detailed analysis to a subsequent rate case.

The Company incorporated its updated SCR analysis from February 2013 into its 2013 IRP, filed in April 2013, with minor updates showing that the benefits of the SCRs had increased, and with additional early retirement scenarios.[247] The Company's IRP analysis demonstrated that SCRs at Jim Bridger Units 3 and 4 were the best compliance option for customers. The same 2013 IRP analysis supported decisions to close the Carbon plant and convert Naughton Unit 3 to natural gas.[248]

The Company's filing in this case is supported by its 2013 IRP SCR economic analysis,

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[244] *Wash. Utils. and Transp. Comm'n v. Pac. Power and Light Co.*, Docket UE-152253, Order 12 ¶ 114 (Sept. 1, 2016); California Public Utility Commission, *In the Matter of the Application of PacifiCorp, an Oregon Company, for an Order Authorizing a General Rate Increase*, A.18-04-002, D.20-02-025 at 35 (Feb. 6, 2020).
[245] PAC/2300, Link/43-45, citing *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, IPUC Case No. IPC-E-13-16, Order No. 32929 at 10 (Dec. 2, 2013); PacifiCorp intends to request recovery of the Jim Bridger assets in Idaho in the Company's next general rate case in that jurisdiction.
[246] Idaho Pub. Util. Comm'n, Order No. 32929 at 10.
[247] PAC/2300, Link/6; PAC/3800, Link/11-12.
[248] *PacifiCorp's 2013 Integrated Resource Plan*, Docket LC 57, Application at 38 (Apr. 30, 2013).

which complies with the Commission's direction in Order No. 12-493 in docket UE 246.[249] While Staff claims that the analysis in the 2013 IRP "generally followed along the same lines as the coal analysis in [docket] UE 246,"[250] this is inaccurate. The analysis in docket UE 246 was performed between 2008-2009, while the SCR analysis in the 2013 IRP was performed in 2012-2013 with the following significant changes and improvements:

First, PacifiCorp's SCR analysis did not examine immediate shut-down in advance of environmental compliance deadlines as an alternative to emission control investments.[251] Instead, the SCR analysis examined multiple early retirement dates, none of which were immediate, and natural gas conversion.

Second, PacifiCorp's SCR analysis included meaningful sensitivity and scenario analyses, following the Commission's direction in Order 12-493: "Major resource decisions should not rely largely on single point forecasts, but should instead be shown to be robust over a wide range of futures/scenarios and input assumptions."[252] The SCR analysis included nine separate price-policy scenarios that accounted for a broad range of future natural gas and carbon dioxide prices. The Company also performed additional sensitivities related to early retirement and avoidance of transmission investments.

Third, PacifiCorp's analysis incorporated potential costs of known, emerging regulations by including carbon costs in its base scenario.[253]

Fourth, PacifiCorp updated its analysis, following Commission direction that, "[w]hile we do not expect a utility to engage in a never-ending process of reconsideration of its

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[249] Order No. 12-493 at 31 (reviewing whether PacifiCorp prudently decided to invest in emissions control investments at seven coal units, in advance of pending environmental compliance obligations).
[250] Staff/700, Soldavini/48-49.
[251] Order No. 12-493 at 29.
[252] *Id.*
[253] *Id.* at 30.

investment decisions, with major resource investments such as these, a reasonable utility would consider changing conditions that significantly impact the financial viability of the investments."[254] The Company prepared its initial analysis in August 2012. The Company then comprehensively updated that analysis in February 2013 and incorporated it into the 2013 IRP. The Company carefully monitored changing market conditions using its regression tools for natural gas prices and carbon prices before issuing the FNTP on December 1, 2013.

Fifth, through its SO model, the Company conducted a full resource portfolio analysis and its PVRR(d) reflected a mix of replacement resources.[255]

In addition to the above improvements to the Company's analysis, the regulatory context for the Company's investment was different and more constrained. As the Commission recognized in Order No. 12-493, the investments at issue in docket UE 246 were subject to more flexible compliance requirements for the reduction of sulfur dioxide emissions, which includes a regional backstop trading program—as compared to the SCR investments in this case that were installed to meet the more stringent unit-by-unit NOx-reduction requirements.[256]

In the 2013 IRP, the Commission concluded that it "lack[ed] the necessary information" to comment on the merits of installing SCRs, and thus declined to acknowledge the investments.[257] CUB claims that the Commission's failure to acknowledge the investments means that the Company's decision to install SCRs was imprudent.[258] Yet, as the Commission has clearly and repeatedly explained, "a decision to not acknowledge an action item does not

[254] *Id*.
[255] *Id*.
[256] *Id*. at 28-30.
[257] *In the Matter of PacifiCorp's 2013 Integrated Resource Plan*, Docket LC 57, Order No. 14-252 at 9 (July 8, 2014).
[258] CUB's Prehearing Brief at 13 ("PacifiCorp chose to bypass Oregon's traditional resource procurement process by installing SCRs even though they had never been acknowledged.").

constitute a preliminary determination of imprudence."[259] The Commission's 2013 IRP Order was explicitly "[b]ased upon the information we have at this time" and "will be more thoroughly investigated in a future rate case proceeding."[260] Here, PacifiCorp has marshalled a comprehensive record that supports the prudence of the Company's SCR investments.

a. Early retirement was not an economically preferable or a feasible option.

The Company compared installation of SCRs to early retirement of Jim Bridger Units 3 and 4 in 2015 and 2016, respectively. This scenario was $588 million more costly than the SCR alternative.[261] PacifiCorp also analyzed early retirement of Jim Bridger Units 3 and 4 in 2020 and 2021, respectively.[262] This early retirement scenario was $174 million more costly than SCRs. Importantly, this scenario was generally analogous to the Boardman example, cited by CUB,[263] where PGE was able to negotiate a shut-down four years after the applicable compliance deadline.[264] Third, in December 2013, PacifiCorp analyzed retirement of Units 3 and 4 in 2022 and 2023, respectively.[265] Once again, this study had a PVRR(d) of $77 million in favor of the SCRs.

While the Company assumed for purposes of the economic analysis that early retirement would have been an acceptable compliance option, this assumption did not account for the central role of the Jim Bridger plant in PacifiCorp's system operations at the time.[266] Staff

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[259] Order No. 14-252 at 2; *see also In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning Requirements*, Docket UM 1056, Order No. 07-002 at 24 (Jan. 8, 2007) (quoting *In The Matter Of The Investigation Into Least-cost Planning In Oregon*, Docket UM 180, Order No. 89-507 at 7 (Apr. 20, 1989)).
[260] Order No. 14-252 at 8.
[261] PAC/700, Link/110.
[262] PAC/3800, Link/12.
[263] CUB/400, Jenks/39.
[264] PAC/3800, Link/12.
[265] The Company provided the 2022-2023 retirement analysis to the parties in the 2013 IRP proceeding on December 13, 2013. *See* PAC/3800, Link/12.
[266] PAC/3800, Link/13.

specifically recommended acknowledgment of the SCRs in the 2013 IRP in part on this basis, highlighting the value provided by Jim Bridger and noting that these units were not viable candidates for early retirement.[267] Compared to Jim Bridger, other plants were more likely contenders for early retirement at that time.[268]

Staff, CUB, AWEC, and Sierra Club criticize the Company for failing to consider a sufficiently broad array of early retirement scenarios.[269] These parties suggest that the Company could have continued to operate the units using coal past the deadline for environmental compliance, in exchange for an agreement to retire the units early. Yet, as noted above, PacifiCorp evaluated a range of early retirement options—including the Boardman-style retirement scenario—and *all* of these scenarios showed that SCRs remained the best compliance option relative to early retirement.[270] Thus, even if deferred early retirement dates akin to the Boardman scenario had been feasible, the available information still favored installing SCRs.

More importantly, however, it is not reasonable to assume that the Company could have negotiated deferred, early retirement for Jim Bridger Units 3 and 4 with either the Wyoming Department of Environment Quality (DEQ) or the U.S. Environmental Protection Agency (EPA).[271] PacifiCorp appealed Wyoming's requirement to install SCRs at Jim Bridger Units 3 and 4, but the state maintained the requirement to install SCRs. Early retirement would also have required modification of the Wyoming SIP. In March 2013, the Company specifically requested

[267] Docket LC 57, Staff's Final Comments at 7-8 (Jan. 10, 2014).
[268] PAC/3800, Link/13-14.
[269] Staff's Prehearing Brief at 37 ("PacifiCorp failed to consider a sufficient number of alternatives to its investment in the Jim Bridger Units 3 and 4 SCRs[.]"); CUB's Prehearing Brief at 13 (stating that PacifiCorp "failed to explore the flexibility that was available to it"); AWEC's Prehearing Brief at 33 ("PacifiCorp failed to consider an alternative compliance option that would allow the Company to run the units on coal until a shut-down of 2025."); Sierra Club's Prehearing Brief at 8 (claiming that PacifiCorp failed to conduct "any meaningful alternatives analysis").
[270] PAC/700, Link/110; PAC/3800, Link/12.
[271] PAC/4000, Owen/4.

that Wyoming modify its long-term strategy compliance timeline for Jim Bridger requirements; Wyoming refused, stating that it was not willing to reopen or modify its SIP, which had already been submitted to EPA for review and approval.[272] Given that Wyoming had already clearly and recently stated that it was not willing to modify its SIP, it was unrealistic to assume that the Company could have negotiated alternative early retirement dates, or any other compliance alternative that depended on such a modification.

Moreover, there was no basis to believe that EPA would not approve the Wyoming SIP as proposed because Wyoming required the most stringent of the available emission control retrofit options, meaning that it was unlikely that EPA would seek to modify those emissions control requirements.[273] In contrast, where Wyoming allowed for installation of *less* stringent LNB and overfire air (OFA) as the best available retrofit technology (BART) for Dave Johnston Unit 3, EPA instead required that the Company either install SCR by January 2019 or cease operation of the unit by December 31, 2027.[274] When PacifiCorp appealed the Wyoming DEQ's requirement to install SCRs at Jim Bridger, EPA specifically advocated for SCRs to be required as part of BART.[275] EPA had also stated it would defer to Wyoming regarding the state's preference for emission control requirements.[276] Thus, there was no reason for PacifiCorp to have reasonably believed that either Wyoming DEQ or EPA would be amenable to removing or postponing the requirement to install SCRs at Jim Bridger Units 3 and 4.

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[272] PAC/830 (rejecting a request that "would entail a revision to our overall SIP with EPA" on the basis that "[t]his is one step that the DEQ-AQD does not intend to undertake at this time").
[273] UE 374 Evidentiary Hearing Transcript (Sept. 10, 2020) (hereinafter "Sept. 10, 2020, Tr."). 95:11-96:8.
[274] PAC/2509, Owen/15.
[275] PAC/4001 (Comments of U.S. Environmental Protection Agency to Wyoming Air Quality Division Regarding Proposed Best Available Retrofit Technology Determinations, Aug. 3, 2009).
[276] *Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule*, 77 FR 33022, 33054 (June 4, 2012) ("[W]e believe it may be appropriate to give considerable deference to the State's conclusions about what controls are reasonable and when they should be implemented[.]").

Sierra Club states that the Company "acknowledg[es]" that early retirement was "readily available," pointing to the Company's assessment of a "[redacted]," in which the Company "[redacted]."[277] Sierra Club is plainly misstating PacifiCorp's analysis, which [redacted] without addressing the alternative's viability.

In addition to other retirement dates, Sierra Club suggests that the Company could have potentially avoided SCRs by making a firm commitment to convert the units to natural gas at a later date.[278] Similarly, AWEC argues that the Company should have explored reduced dispatch as a further alternative to SCRs.[279] Neither of these options was realistic at the time. Delayed natural gas conversion would have required the same revisions to Wyoming's SIP as would have been necessary for deferred retirement. And while PacifiCorp has recently pursued implementation of visibility-tailored emission limits at the Jim Bridger plant in lieu of emissions control retrofits at Jim Bridger Units 1 and 2 (made possible, in part, by the presence of SCRs on Units 3 and 4), neither operators nor regulators (nor, indeed, any other parties) had yet conceived of this compliance strategy as a possible compliance option in 2013. Importantly, while the Commission recognizes that the prudence standard is a high standard,[280] multiple options can be considered prudent.[281] Here, the overwhelming weight of the evidence supported PacifiCorp's conclusion that SCRs were the best available compliance option for customers.

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[277] Sierra Club's Prehearing Brief at 25 (quoting Confidential Cross Examination Exhibit Sierra Club/700).
[278] Sierra Club/400, Fisher/23.
[279] AWEC/500, Kaufman/10.
[280] *In the Matter of Portland General Electric Company Application for Annual Adjustment to Schedule 125 Under the Terms of the Resource Valuation Mechanism*, Docket UE 139, Order No. 02-772 at 11 (Oct. 30, 2002).
[281] Order No. 12-493 at 25.

b. PacifiCorp appropriately evaluated SCRs using the 20-year depreciable life required by EPA.

AWEC[282] and CUB[283] argue that the Company should have evaluated SCRs based on the 2025 depreciable life then in effect for the Jim Bridger plant. PacifiCorp applied a 20-year depreciable life for SCRs as mandated by EPA.[284] EPA does not consider the existing depreciable life of the underlying plant as the relevant metric for determining the useful life of emissions control equipment, given that "the depreciable life is often shorter than the economic life of [a] facility."[285] Moreover, applying Oregon's 2025 depreciable life for Units 3 and 4 did not change the outcome of the Company's economic analysis—SCRs remained favorable by a significant margin.[286]

c. PacifiCorp appropriately did not include independent or speculative variables to evaluate different compliance options.

Staff and Sierra Club claim that the Company's analysis should have considered the benefits of avoiding certain transmission investments in Gateway West by retiring the Jim Bridger units.[287] As PacifiCorp explained at hearing, no transmission investment would have been avoided because the decision to build Gateway West was independent of continued operation of Jim Bridger Units 3 and 4.[288] Sierra Club simplistically assumes that constraints east of Jim Bridger have no impact on the need for transmission investment west of Jim Bridger. In fact, during high transfer conditions from eastern Wyoming to central Utah, if the Gateway South transmission line trips, then the remaining power will overload the existing 345 kilovolt

[282] AWEC's Prehearing Brief at 33 ("PacifiCorp's analysis failed to put appropriate weight on Oregon's transition away from coal, even in 2013, by assuming a useful life for Jim Bridger of 2037, rather than 2025[.]").
[283] CUB's Prehearing Brief at 13 ("Making and installing an investment with a useful life that is ten years longer than the plant it is being added to is not in the interest of Oregon customers.").
[284] PAC/4004.
[285] PAC/2509, Owen/135 (EPA's Wyoming Regional Haze Decision).
[286] PAC/3800, Link/2.
[287] Staff's Prehearing Brief at 37-38; Sierra Club/400, Fisher/24.
[288] Sep. 9, 2020, Tr. 238:25-239:5; PAC/3800, Link/21.

(kV) lines west of Jim Bridger above their thermal ratings.[289]

AWEC also argues that the Company should have considered the value of the water rights associated with Jim Bridger units in the analysis of the costs and benefits of retirement.[290] As explained in detail by PacifiCorp witness Mr. Dana Ralston, it is extremely difficult to forecast both the saleable amount and potential value of the Company's water rights, but it is clear that the value would not have been material.[291] PacifiCorp would have been imprudent to base its investment decision on such a speculative variable.

3. PacifiCorp reasonably concluded that SCRs remained the best compliance option for customers before making a final decision in December 2013.

Due to the Company's innovative EPC contracting process, the Company was able to continue evaluating the decision to pursue SCRs even after signing the EPC contract on May 31, 2013, up to issuance of the FNTP on December 1, 2013.[292] 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.[293] Nonetheless, Sierra Club now claims that third-party gas price forecasts had declined "dramatically,"[294] that coal prices had increased "significantly,"[295] and that the Company should have further delayed the SCR decision until after December 1, 2013.[296] Sierra Club is mistaken on all counts.

a. The latest third-party gas price forecasts continued to show that SCRs were the best compliance option for customers.

PacifiCorp's decision to issue the FNTP was based on the September 2013 official

[289] PAC/4200, Vail/47.
[290] AWEC's Prehearing Brief at 33.
[291] PAC/4100, Ralston/16.
[292] PAC/700, Link/106.
[293] PAC/700, Link/107.
[294] Sierra Club's Prehearing Brief at 9.
[295] Sierra Club's Prehearing Brief at 14.
[296] Sierra Club's Prehearing Brief at 23.

forward price curve (OFPC), as informed by market changes (or lack thereof) occurring before December 1, 2013.[297] PacifiCorp develops its quarterly OFPCs using three third-party expert forecasts, and the OFPC is then used in a range of regulatory and business contexts—including setting customer rates, developing avoided cost prices for qualifying facilities, and least-cost, least-risk resource planning in the IRP.[298] PacifiCorp's development of the September 2013 OFPC was not tied to the SCR decision and reflected the Company's most accurate estimate of long-term gas prices.[299] The September 2013 OFPC showed that the nominal levelized price for long-term gas prices remained at $5.35/million British thermal units (MMBtu)—well above the breakeven point of $4.86/MMBtu.

Sierra Club argues that the Company should not have relied on the September 2013 OFPC, and instead should have developed an out-of-cycle OFPC before December 1, 2013.[300] There was no reason to have developed such an ad-hoc forecast, nor would doing so have impacted the analysis. Of the three forecasts used for the September 2013 OFPC, PacifiCorp received updates for two prior to issuing the FNTP on December 1, 2013—one showing a nominal levelized price that was 20 cents *higher* than the 2013 OFPC, and the other showing a decline of less than one percent relative to the same consultant's August forecast.[301] The remaining forecast, [redacted], was partially updated in October for short-term gas prices only, but this update would have had no impact on the OFPC because it concerned the near-term portion of the forecast that would be routinely replaced by market forwards in the Company's OFPC development process.[302] As explained at hearing, if the Company had used the partially updated

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297 PAC/3800, Link/5.
298 Sept. 10, 2020, Tr. 74:20-75:14; UE 374 Evidentiary Hearing Transcript (Sept. 11, 2020) (hereinafter "Sept. 11, 2020, Tr.") 53:9-54:4.
299 Sept. 10, 2020, Tr. 74:20-75:14.
300 Sierra Club's Prehearing Brief at 9-10.
301 PAC/3800, Link/5-6.
302 Sept. 11, 2020, Tr. 43:23-44:4.

October [redacted] forecast, the benefits of the SCRs would have been even higher.[303] Even using the December 2013 OFPC, the SCRs were still the lowest cost option by $36.7 million.[304]

Moreover, Sierra Club's focus on natural gas prices leading up to December 1, 2013, reflects improper hindsight review. Sierra Club's comments filed in the 2013 IRP during this time period were not focused on supposedly rapidly declining natural gas prices.[305] The fact Sierra Club's contemporaneous comments never claimed gas prices were a red flag is evidence that its position here is informed more by events that occurred in the years following 2013 than on what the Company knew or should have known on December 1, 2013.

b. The October 2013 mine plan did not indicate major changes in the relative cost of SCRs.

PacifiCorp's economic analysis of fueling costs for Jim Bridger was appropriately based on the January 2013 long-term fueling plan (also known as the long-term fueling forecast) for the Jim Bridger plant.[306] This analysis showed that the relative benefit of installing SCRs, as compared to a natural gas conversion, was approximately $130 million before PacifiCorp issued its FNTP.[307] Sierra Club argues that the October 2013 mine plan resulted in a $59.3 million reduction in SCR benefits.[308] While the SCRs would have remained the most cost-effective option even assuming this was true, Sierra Club's argument is incorrect in two key respects.

First, the Company's 2013 mine plan did not indicate that coal costs had increased substantially. The October 2013 mine plan increased certain costs, but there were also offsetting

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[303] Tr. Sept. 11, 2020, Tr. 41:1-5.
[304] Sierra Club/400, Fisher/3.
[305] *See, e.g.,* Docket LC 57, Sierra Club's Preliminary Comments on PacifiCorp 2013 Integrated Resource Plan (Aug. 22. 2013); *In the Matter of PacifiCorp's 2013 Integrated Resource Plan*, Docket LC 57, Sierra Club's Supplemental Opening Comments (Jan. 17, 2014); Docket LC 57, Sierra Club's Final Comments on PacifiCorp 2013 Integrated Resource Plan (Jan. 10, 2014).
[306] PAC/4100, Ralston/4.
[307] PAC/3800, Link/5.
[308] Sierra Club's Prehearing Brief at 18.

cost decreases, such as decreased capital cost requirements as the underground mine closed sooner than expected.[309] Sierra Club's analysis simply identifies one cost change from the 2013 mine plan—$28.3 million in reduced remediation costs—and ignores all other changes. Indeed, even if the Company had performed a revised analysis based on this mine plan, the results would still have favored installing the Jim Bridger SCRs, as the October 2013 mine plan reduced the $130 million in relative benefits by only $16.7 million over the 10-year mine plan period.[310]

Second, Sierra Club's $59.3 million figure continues to rely on analysis of the November 2014 long-term fueling plan, developed for use in the 2015 IRP.[311] This analysis is misplaced because a prudence analysis considers "the reasonableness of [a utility's] actions based on information that was available (or could reasonably have been available) at the time."[312] PacifiCorp did not have the November 2014 long-term fueling plan when it issued the FNTP on December 1, 2013. While PacifiCorp calculated what the impact would have been *if* the Company had known the next year's long-term fueling plan, this analysis was conducted to rebut Sierra Club's claim that coal costs had increased by $143 million—a claim that Sierra Club has since abandoned.[313] Even relying on the November 2014 long-term fueling plan, the total cost increase from the January 2013 long-term fueling plan was only $31 million—not $59.3 million.

c. PacifiCorp could not further delay the final decision to pursue SCRs.

Through the phased EPC, PacifiCorp had already delayed the final SCR decision as long as possible for cost-effective installation, while still allowing sufficient time to meet the

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309 PAC/4100, Ralston/7.
310 PAC/4100, Ralston/8.
311 PAC/4100, Ralston/3.
312 *In re PGE*, Docket UE 102, Order No. 99-033 at 36-37 (Jan. 27, 1999). *See also In re Northwest Natural Gas*, Docket UG 132, Order No. 99-697 at 52 (Nov. 12, 1999) ("In this review, therefore, we must determine whether NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.").
313 PAC/4100, Ralston/4.

compliance deadlines.[314] Sierra Club argues that the Company should have delayed the timeline further still to allow for a detailed reassessment of the available compliance options.[315] A decision to delay would functionally have been a decision to not install the SCRs, which was contrary to the results of PacifiCorp's economic analysis.

4. PacifiCorp was obligated to comply with Wyoming's 2015-2016 environmental compliance deadlines for Jim Bridger Units 3 and 4.

When PacifiCorp applied for a BART permit for Jim Bridger Units 3 and 4, PacifiCorp made it clear that the appropriate BART controls should be LNB and OFA—not SCRs.[316] While the Wyoming DEQ agreed not to require SCRs as BART, it instead mandated that SCRs be installed in 2015 and 2016 as part of the state's long-term strategy, and incorporated the SCR requirement into the December 31, 2009, BART permit. This permit established a legal obligation for PacifiCorp to comply. Indeed, the Wyoming PSC explicitly stated that the Company had "a legal obligation . . . to complete the work on Jim Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively."[317]

Sierra Club and CUB incorrectly argue that the Company was not subject to an enforceable compliance deadline to install SCRs by 2015 and 2016 because the Wyoming DEQ decision remained subject to potential modification by EPA.[318] While the Wyoming DEQ settlement anticipated that EPA would review the SIP and that EPA had the authority to approve or disapprove specific provisions, the agreement was also clear that, "unless EPA affirmatively disapproves such portions of the Wyoming regional haze SIP in a final rulemaking, the parties

[314] PAC/2300, Link/7.
[315] Sierra Club's Prehearing Brief at 23.
[316] PAC/2500, Owen/3.
[317] PAC/2516 (*In the Matter of the Application of Rocky Mountain Power for Approval of Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4 Located Near Point of Rocks, Wyoming*, WPSC Docket No. 20000-418-EA-12 (Record No. 13314), Order Denying Motion for a Stay or Continuance Pending Final EPA Action, ¶ 14 (Feb. 4, 2013) (Wyoming Stay Order)).
[318] Sierra Club/400, Fisher/33-34; CUB/400, Jenks/44.

shall continue to abide by the terms" of the settlement agreement.[319] EPA never affirmatively disapproved the applicable portions of the SIP.

The fact that EPA had not yet granted final approval of the SIP is irrelevant to the SIP's enforceability because states and local governments retain the primary responsibility for air pollution control under the Clean Air Act (CAA).[320] EPA's evaluation of a SIP specifically looks to confirm that the SIP has been made *enforceable* at the state level, either by "adopt[ing] the [SIP] in the State code or body of regulations," or by implementing the SIP through a "permit, order, [or] consent agreement . . . in final form."[321]

Sierra Club and CUB also incorrectly suggest that EPA's approval of Wyoming's SIP extended the deadline for compliance by an additional five years from the date of approval.[322] As EPA has explained, the five-year period following EPA's SIP approval is the *outer limit* for any compliance deadlines, not the new universal compliance date for all SIP mandates: "Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but *no later than* five years after the date of EPA approval of the regional haze SIP."[323]

5. Any disallowance should be limited to a one-time 10 percent adjustment, consistent with Order No. 12-493.

If the Commission believes that a disallowance is required in this case, then it should be capped at the Commission's previous disallowance in Order No. 12-493 in docket UE 246, as the Company has clearly strengthened the rigor of its analysis from the analysis considered in that

[319] PAC/2510 (November 3, 2010 Wyoming BART Appeal Settlement Agreement) (emphasis added).
[320] 42 USC § 7401(a) ("The Congress finds . . . that air pollution prevention . . . and air pollution control at its source is the primary responsibility of States and local governments[.]").
[321] 40 CFR Appendix V to Part 51 (2.0(b)).
[322] CUB/400, Jenks/41; Sierra Club's Prehearing Brief at 28.
[323] Federal Register Volume 77, Number 95, 40 CFR Part 52 (May 16, 2012) (emphasis added) (citing CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv)).

proceeding.[324] In that case, the Commission disallowed 10 percent of the Oregon-allocated share of the Company's cost recovery request—that is, 10 percent of the remaining undepreciated balance.[325] The Commission also directed that, to simplify tracking of recovery over the investments' useful lives, the adjustment not be made directly to rate base, but rather through a tariff rider crediting ratepayers for the disallowed amount.[326]

Staff argues for a 10 percent disallowance based on total (rather than net or depreciated) value of the Jim Bridger SCRs, and for a disallowance that would apply each year.[327] While Staff describes this proposal as a "slight difference in methodology" from that approved in Order No. 12-493, the impact is significant because the Company has already absorbed $13.3 million in Oregon depreciation for the Jim Bridger SCRs as a result of regulatory lag.[328] Thus, Staff's adjustment would disallow a far greater share of the costs for which the Company now seeks recovery. Staff does not explain why the Commission should depart from past practice in calculating a management disallowance in this case, and the Commission should not do so.

B. PacifiCorp prudently declined to challenge installation of SCRs at Hayden Units 1 and 2 because these investments were legally required.

Based on PacifiCorp's economic and legal analysis, the Company prudently allowed installation of SCRs at the Hayden plant.[329] PacifiCorp is a minority owner of Hayden Units 1 and 2, together with Public Service Company of Colorado (PSCo) and Salt River Project.[330] This joint ownership is governed by a Participation Agreement, which mandates installation of capital

[324] Order No. 12-493 at 31; *see* PacifiCorp's Prehearing Brief at 32-33.
[325] Order No. 12-493 at 32.
[326] Order No. 12-493 at 32.
[327] Staff's Prehearing Brief at 38.
[328] PAC/4400, McCoy/19.
[329] PAC/2600, Ralston/34. Given the similarity between Units 1 and 2, the specificity of the environmental compliance requirements, and the overarching limitations of the Participation Agreement, PacifiCorp determined it was not necessary to conduct parallel economic analysis of Hayden Unit 2. PAC/2600, Ralston/41.
[330] PAC/800, Teply/48.

improvements required by law.[331] Under the Hayden Participation Agreement, PSCo as the Operating Agent has an independent obligation to operate the units in accordance with all environmental laws.[332] Where the Operating Agent proposes a capital improvement (such as SCRs) to comply with applicable law, a non-consenting owner's only option is to assert that the capital addition is *not* required by applicable law.[333] Such a dispute would then be decided through arbitration.

The Colorado Regional Haze SIP required the installation of SCRs at Hayden Units 1 and 2 by the end of 2015 and 2016, respectively.[334] Further, the Colorado Public Utilities Commission (Colorado PUC) approved a plan for emissions reductions under the state's Clean Air Clean Jobs Act (CACJA), which included installation of SCRs on both units.[335] In light of these clear legal obligations, the joint owners installed SCRs on Hayden Units 1 and 2 in May 2015 and August 2016, respectively.[336] While PacifiCorp explored divesting its share of Hayden Units 1 and 2, the Company did not receive any expressions of interest in its share of the units.[337]

Sierra Club claims that the Company was imprudent for failing to oppose installation of SCRs at Hayden Units 1 and 2, and for declining to pursue arbitration against its co-owners.[338] Specifically, Sierra Club argues that the SCRs were not legally required because neither the Colorado SIP nor the Colorado PUC-approved CACJA plan was legally binding, and that PacifiCorp should therefore have reasonably expected to prevail in arbitration.[339]

[331] PAC/2600, Ralston/32.
[332] PAC/2600, Ralston/32.
[333] PAC/2600, Ralston/34.
[334] PAC/2607 (Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan, 77 FR 76871 (Dec. 31, 2012)).
[335] PAC/2600, Ralston/33.
[336] PAC/800, Teply/3; PAC/2600, Ralston/31.
[337] PAC/2600, Ralston/41.
[338] Sierra Club's Prehearing Brief at 26.
[339] Sierra Club's Prehearing Brief at 26-27.

First, Sierra Club is incorrect that the Colorado SIP's requirement to install SCRs was non-binding. As explained above, states bear the primary responsibility for implementing the CAA and the regional haze rule through state-specific SIPs, which are then reviewed by EPA for consistency with federal requirements[340]—including the requirement that the SIP be enforceable.[341] The fact that EPA had not yet reviewed and confirmed the validity of Colorado's SIP did not make the SIP less binding in the interim, nor did EPA's approval of the SIP void Colorado's clear deadlines for unit-specific emissions reductions.

Second, Sierra Club is incorrect that the CACJA compliance plan, approved by the Colorado PUC, was non-binding. The CACJA required companies to file a plan for emissions reduction in the state, subject to approval by the Colorado PUC.[342] The Colorado PUC explicitly approved PSCo's plan to install SCRs at Hayden Units 1 and 2 as "needed and in the public interest for emission reduction purposes."[343] Sierra Club's position that the CACJA required submission and approval of a plan, but not compliance with that plan, is untenable.

Sierra Club also claims that the Company's own analysis demonstrated that the SCRs were uneconomic.[344] On the contrary, PacifiCorp concluded that SCRs were the more favorable economic option, in light of the coal contract take-or-pay termination costs that would likely apply if PacifiCorp pursued early retirement to avoid SCR investments for economic reasons.[345]

[340] 42 USC § 7401(a) ("The Congress finds . . . that air pollution prevention . . . is the primary responsibility of States and local governments[.]").
[341] 40 CFR Appendix B part 51 (requiring "[e]vidence that the State has adopted the plan in the State code or body of regulations; or issued the permit, order, consent agreement (hereafter "document") in final form. That evidence shall include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date").
[342] Colo. Rev. Stat. § 40-3.2-204.
[343] PAC/2604 (Colorado Public Utilities Commission Docket No. 10M-245E, Decision No. C10-1328 at 45 ("[W]e find that SCR controls on Hayden 1 and 2 are needed and in the public interest for emission reduction purposes.")).
[344] Sierra Club's Prehearing Brief at 26-27.
[345] PAC/2600, Ralston/37 (explaining that, in the case where coal contract termination costs applied, the installation of SCRs was more economic for customers).

When Sierra Club raised similar arguments before the Wyoming PSC, that commission rejected Sierra Club's arguments.[346] The Wyoming PSC noted, among other things, that the Company "pursued selling its interest in Hayden Unit 1 as an alternative to incurring environmental compliance costs, including an open-ended Request for Expressions of Interest in Hayden Units 1 and 2" but that the Company "did not receive any responses to the Request for Expressions of Interest."[347] Sierra Club also challenged the prudence of the Company's SCR investments at Hayden in PacifiCorp's 2019 California rate case proceeding. Again, the California Commission concluded that the Company's SCR investments were reasonable and necessary and approved full cost recovery.[348]

C. <u>PacifiCorp prudently installed low-NOx burners and a baghouse at Hunter Unit 1.</u>

PacifiCorp seeks recovery for the costs of LNB and a baghouse at Hunter Unit 1.[349] These emissions control upgrades were part of the Company's emissions compliance obligations under the State of Utah's Regional SIP and associated permits. These projects were placed in service in May 2014, in advance of the April 16, 2015 compliance deadline.[350] As PacifiCorp witness Mr. Rick Link explained at length, the Company's analysis of the compliance scenarios for Hunter Unit 1 was performed using the SO model and considered early unit retirement and conversion to natural gas, as well as the potential for future emissions control requirements.[351] This analysis consistently showed that installation of the LNB and baghouse equipment was the

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[346] *In the Matter of Rocky Mountain Power Company Request for Approval of a General Rate Increase*, WYPSC Docket No. 20000-446-ER-14 (Record No. 13816), Findings of Fact, Conclusions of Law, Decision, and Order at ¶ 82 (Dec. 30, 2014).
[347] *Id.* at ¶ 80.
[348] California Public Utility Commission, *In the Matter of the Application of PacifiCorp, an Oregon Company, for an Order Authorizing a General Rate Increase*, A.18-04-002, D.20-02-025 at 35 (Feb. 6, 2020).
[349] PAC/800, Teply/3.
[350] PAC/2300, Link/47; PAC/800, Teply/39.
[351] PAC/2300, Link/46-50.

lowest cost and best option for customers.[352]

Despite failing to file substantive rebuttal testimony, AWEC continues to oppose cost recovery for the Hunter emissions control investments for two reasons: (1) the Commission declined to acknowledge the investments in PacifiCorp's 2013 IRP;[353] and (2) it would have been more cost-effective to retire Hunter Unit 1 in 2029, at the end of the unit's Oregon depreciable life.[354]

First, as noted above, the Commission has clearly and repeatedly stated that whether an investment decision is acknowledged is not dispositive of an investment's prudence.[355] Moreover, the Commission's decision not to acknowledge PacifiCorp's action item for Hunter Unit 1 was not based on a substantive concern with the planned investment, but rather with the fact that the project was already underway.[356]

Second, AWEC's argument that PacifiCorp should have operated Hunter Unit 1 without the required emissions control technologies unreasonably assumes that the Company could have operated the unit for *14 years* past the emissions compliance deadline, without consequence. As PacifiCorp witness Mr. James Owen has explained, a prudent utility does not and cannot plan to operate its units in contravention of clear compliance requirements.[357] Moreover, as explained by PacifiCorp witness Mr. Link, PacifiCorp modeled a range of compliance scenarios including early retirement.[358] This analysis consistently showed that installation of baghouse and LNB equipment was the lowest cost and best option for customers.[359]

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352 PAC/2300, Link/50.
353 AWEC/300, Kaufman/45; AWEC's Prehearing Brief at 35.
354 AWEC's Prehearing Brief at 36.
355 Order No. 14-252 at 2; *see also* Order No. 07-002 at 24 (quoting Order No. 89-507 at 7).
356 Order No. 14-252 at 7.
357 Sept. 11, 2020, Tr. 108:13-16.
358 PAC/2300, Link/49-50.
359 PAC/2300, Link/50.

In addition, AWEC's analysis of a 2029 retirement scenario is so flawed as to be essentially useless.[360] While PacifiCorp bears the initial burden to demonstrate the prudence of a capital investment, intervening parties opposing cost recovery must present an evidentiary basis to "show that the costs are not reasonable."[361] Here, AWEC's analysis does not provide the evidentiary basis necessary to support an adjustment. AWEC witness Dr. Lance Kaufman used a "seemingly random application of adjustment percentages" and applied unexplained adjustments to certain line items in the Company's analysis.[362] Indeed, even after PacifiCorp identified the numerous problems with Dr. Kaufman's analysis, AWEC declined to substantively respond to these concerns, and merely stated that the Company had misinterpreted and "discredit[ed]" AWEC's analysis.[363]

D. <u>PacifiCorp accurately applied the Commission-approved depreciation rate to the Company's generating plant investments.</u>

Under ORS 757.140, PacifiCorp must depreciate its assets using rates of depreciation approved by the Commission.[364] PacifiCorp's generating plants depreciate using the group depreciation method, which is standard practice in the utility industry.[365] Under group depreciation, assets within the group depreciate at a set annual percentage rate that is approved by the Commission.[366] Investments added to a depreciation group between depreciation rate updates *must* depreciate at the approved percentage rate.[367] When a utility files to update its

[360] PAC/2300, Link/48-49.
[361] *In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket UE 116, Order No. 01-787 at 7 (Sept. 7, 2001) (quoting Order No. 99-697 (Nov. 12, 1999)).
[362] PAC/2300, Link/48-49.
[363] AWEC/500, Kaufman/6.
[364] ORS 757.140(1) ("Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the [C]ommission.")
[365] PAC/4400, McCoy/17.
[366] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates*, Docket UM 1647, Order No. 13-347 at 1-2 (Sept. 25, 2013).
[367] PAC/4400, McCoy/17.

depreciation rates, the percentage rates for group depreciation assets are revised to allow the entire group to fully depreciate by the end of the collective asset's depreciable life.[368]

Here, PacifiCorp invested in its generating facilities at Jim Bridger Units 3 and 4, Hunter Unit 1, Craig Unit 2, and Hayden Units 1 and 2. Each of these units are subject to group depreciation, meaning that investments made to these plants must depreciate at the Commission-approved rate. At the time these investments were placed in service and began depreciating, the operative rates of depreciation were those approved by the Commission in Order No. 13-347 in docket UM 1647. In that order, the Commission approved an all-party settlement between PacifiCorp, Staff, CUB, and AWEC (then, the Industrial Customers of Northwest Utilities), which specifically included "group depreciation rates derived for each depreciation group."[369] PacifiCorp applied this Commission-approved group depreciation rate to the new generating plant investments.[370]

Staff and CUB propose to modify the Company's calculation of depreciation for these generation investments by retrospectively applying a higher rate of depreciation, thus increasing the proportion of the Company's investments that would be lost to regulatory lag.[371] Staff and CUB argue that an increased rate of depreciation is appropriate to align the depreciable lives of these investments with the depreciable lives of the underlying generating assets. This approach is simply incorrect in this instance. PacifiCorp's investments in generation assets are clearly subject to the group rates of depreciation, recognized by these parties in docket UM 1647, and approved

[368] PAC/4400, McCoy/17.
[369] Order No. 13-347 at 3.
[370] PAC/4400, McCoy/14-15.
[371] CUB's Prehearing Brief at 13; Staff's Prehearing Brief at 38. Previously, Staff had also expressed concern that the Company's net book value for the Hayden and Craig SCRs and for the Hunter LNB and baghouse were reflected in rate base at their June 30, 2019 balances. Staff/2300, Soldavini/55. Staff's concern was based on an error in PacifiCorp's response to Staff Data Request 750, which PacifiCorp subsequently corrected and explained in surrebuttal testimony. PAC/4400, McCoy/19. Staff does not raise this issue in its Prehearing Brief and PacifiCorp therefore understands that this issue has been resolved.

by the Commission in Order No. 13-347.

VI. CHOLLA UNIT 4, TAX CUT AND JOBS ACT, AND THE GENERATION PLANT REMOVAL ADJUSTMENT

A. The Commission should approve PacifiCorp's proposal to offset Cholla Unit 4 costs with TCJA benefits.

PacifiCorp proposes to retire Cholla Unit 4 by December 31, 2020, and to buy down the undepreciated plant balance and closure costs using TCJA benefits.[372] The remaining TCJA balance, estimated to be $13.3 million, would then be returned to customers over two years, resulting in a $6.9 million annual credit.[373] CUB and AWEC support the Company's proposal, with the understanding that future closure costs included in the Cholla Unit 4 balance would be subject to a prudence review or refund if actual costs are lower or disallowed.[374] Staff supports offsetting TCJA benefits against the undepreciated plant balance, but opposes offsetting closure costs on the basis that the Commission must have "an opportunity to review the reasonableness of [closure] costs[.]"[375] However, as PacifiCorp has explained, the Commission *does* retain the ability to review the prudency of the Company's costs and these costs will be trued up.[376] Any difference between the Company's estimate and actual costs will be addressed in a future ratemaking proceeding.[377] Thus, Staff's concern regarding closure costs has been resolved and the Commission should approve PacifiCorp's proposal to offset all remaining Cholla Unit 4 costs with TCJA benefits.

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372 PAC/3300, Lockey/3, 6.
373 PAC/4400, McCoy/8.
374 CUB's Prehearing Brief at 17; AWEC's Prehearing Brief at 45 (citing AWEC/704, PacifiCorp's Response to AWEC Data Request 0159).
375 Staff's Prehearing Brief at 51-52 (citing AWEC/500, Kaufman/18-19).
376 PAC/4400, McCoy/24.
377 PAC/4400, McCoy/24.

B. <u>If the Commission does not offset Cholla Unit 4 costs with TCJA benefits, then the Commission should approve the Generation Plant Removal Adjustment.</u>

The Company proposed a new Generation Plant Removal Adjustment (GPRA) mechanism to allow recovery of costs associated with the closure or termination of its ownership interest in coal-fired generation plants and to provide a credit to customers for the revenue requirement associated with removed plant between rate cases.[378] The GPRA was designed to function like an automatic adjustment clause, allowing for near-contemporaneous removal from rates of coal resources without filing a rate case.[379] Thirty days in advance of a Commission-approved Exit Date, the Company would file an advice letter to credit customers through a separate tariff adjustment, reflecting the revenue requirement identified in the previous rate case. Then, in the following rate case, the coal-fired resource would be removed from rates and the tariff adjustment revenue requirement reduced to zero.[380]

The Company subsequently proposed to offset the Cholla Unit 4 undepreciated plant balances and closure costs with the TCJA benefits as part of its effort to reduce rate impacts on customers. As a result, there is no immediate need for the GPRA mechanism, if the Commission approves the full Cholla/TCJA offset.[381] If the Commission declines to approve the full Cholla/TCJA offset (including both undepreciated balances and closure costs), then the GPRA would provide the appropriate mechanism to recover costs associated with the removal of Cholla Unit 4 from service, and the Commissions should approve the GPRA to facilitate near-term cost recovery. The Company's primary recommendation remains to offset the Cholla Unit 4 undepreciated balance and closure costs using the TCJA benefits, and to defer consideration of a

[378] PAC/3300, Lockey/33.
[379] PAC/2000, Wilding/42-43.
[380] PAC/2000, Wildling/43.
[381] PAC/3300, Lockey/33-34.

generation plant recovery mechanism to a future proceeding.

C. **<u>The Commission should reject Staff's proposed automatic adjustment clause for recovering coal-fired generation costs.</u>**

Staff asks the Commission to adopt a new automatic adjustment clause (AAC) in this proceeding to recover costs for the Company's undepreciated plant balances associated with its remaining coal-fired generating facilities, with the exception of Cholla Unit 4.[382] Staff's AAC was proposed as an alternative to the Company's GPRA mechanism.[383] Given that the Company has withdrawn its GPRA proposal (subject to approval of the full Cholla/TCJA offset), adopting an alternate regulatory mechanism over PacifiCorp's objection is unnecessary and inappropriate. Moreover, Staff's AAC mechanism is inconsistent with other AACs that currently allow for accelerated cost recovery for coal-fired generating units, in that it includes an annual depreciation update.[384] While PacifiCorp appreciates the need for a cost recovery mechanism as coal-fired generation facilities are removed from rates, PacifiCorp does not believe that Staff's mechanism is appropriate, or that this mechanism needs to be addressed in this already complex case. PacifiCorp intends to present an appropriate mechanism for the Commission's review in a future proceeding, consistent with the 2020 Protocol, and Staff's AAC should therefore be denied.

D. **<u>Cholla Unit 4 property tax remains a valid Test Year expense.</u>**

AWEC proposes to disallow property taxes for Cholla Unit 4 property on the basis that the property will no longer be used or useful.[385] Arizona law results in the expensing and

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[382] Staff's Prehearing Brief at 52.
[383] Staff/1500, Anderson/21-23.
[384] *See, e.g., In the Matter of Idaho Power Co. Application for Authority to Increase Rates for Elec. Serv. to Recover Costs Associated with N. Valmy Power Plant*, Docket UE 316, Order No. 17-235 at 9 (June 30, 2017) (explaining that annual updates would update projected decommissioning expense, but not depreciation expense unless the unit's end-of-life changed).
[385] AWEC's Prehearing Brief at 45-46.

payment of tax in the year following the year of valuation. On January 1, 2020, Cholla Unit 4 was still operating, used, and useful.[386] The Company should not be precluded from recovering lawfully imposed taxes merely because of that state's particular timeline for tax assessment.[387] In the alternative, AWEC proposes that property taxes for Cholla Unit 4 property in 2021 should be deferred for later recovery, to avoid including that cost in long-term rates.[388] This proposal inappropriately cherry-picks a single prudent test year expense for removal, without considering corresponding offsetting cost increases that the Company may incur in subsequent years.

VII. COAL PLANT EXIT DATES AND EXIT ORDERS

A. <u>The Commission should issue Exit Orders consistent with the 2020 Protocol.</u>

PacifiCorp requests that the Commission issue Exit Orders[389] for the Company's coal-fired facilities with Exit Dates[390] consistent with the 2020 Protocol.[391] The 2020 Protocol included agreed-upon Exit Dates for Oregon for coal-fired resources, consistent with ORS 757.518's requirement to eliminate coal-fired generation from the resources used to serve Oregon retail customers by 2030.[392] Stipulating parties, including PacifiCorp, Staff, CUB, AWEC, and Sierra Club, all agreed to support these dates, except for the Hayden plant.[393]

Initially, PacifiCorp sought Exit Orders for all of the Company's coal-fired facilities addressed by the 2020 Protocol. Staff objected and clarified that the Company can request an Exit Order outside of a rate case proceeding. Based on this clarification, PacifiCorp agreed to

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[386] PAC/4400, McCoy/27.
[387] PAC/4400, McCoy/27.
[388] AWEC's Prehearing Brief at 46.
[389] An Exit Order is an order entered by a state commission approving the discontinuation of the use of an existing resource and exclusion of costs and benefits of that resource from customer rates by that state on a date certain. PacifiCorp's 2020 Protocol, Appendix A (Definitions).
[390] Exit Date means the date on which PacifiCorp will discontinue the allocation and assignment of costs and benefits of a coal-fired Interim Period Resource to the State issuing the Exit Order.
[391] PAC/200, Lockey/13; PAC/3300, Lockey/27-28.
[392] PAC/200, Lockey/14.
[393] PAC/200, Lockey/14.

withdraw its request for Exit Orders for units at Hunter, Huntington, and Wyodak.[394] PacifiCorp now seeks the following Exit Orders and corresponding Exit Dates: December 31, 2020 (Cholla Unit 4); December 31, 2023 (Jim Bridger Unit 1); December 31, 2025 (Craig Unit 1, Jim Bridger Units 2-4; Naughton Units 1-2); December 31, 2026 (Craig Unit 2); December 31, 2027 (Colstrip Units 3-4; Dave Johnston Units 1-4).

B. **The Commission should reject Sierra Club's attempt to revise the agreed-upon Exit Dates.**

Despite the parties' agreement in the 2020 Protocol, Sierra Club asks the Commission to approve Exit Dates for all of the Company's coal-fired facilities that are no later than the end of 2025.[395] Sierra Club claims that a "plethora" of evidence supports diverging from the parties' agreed-upon dates, but points to only two purportedly "changed and unforeseen circumstances": (1) EO 20-04 and (2) the COVID-19 pandemic.[396] EO 20-04 does not dictate a change from the 2020 Protocol's agreed-upon Exit Dates because these dates balance EO 20-04's direction to pursue "rapid progress towards reducing GHG emissions,"[397] while also ensuring that these reductions are "at reasonable costs[.]"[398] EO 20-04 does not—and could not—override the Commission's traditional statutory duty to ensure reasonable rates for customers under a least-cost, least-risk framework.[399] Similarly, the COVID-19 pandemic's near-term impacts on demand and market prices does not dictate revisiting the Company's long-term resource decision without careful system-wide analysis. As Sierra Club acknowledges,[400] system-wide resource changes and their impacts are best addressed in an IRP—not in a general rate case where

394 PAC/3300, Lockey/28.
395 Sierra Club/300, Hausman/3.
396 Sierra Club's Prehearing Brief at 29.
397 EO 20-04 at 8.
398 EO 20-04 at 8.
399 Oregon's Constitution precludes the Governor from exercising legislative functions. Oregon Const. art. III, § 1.
400 Sierra Club/500, Hausman/7.

responsive testimony and analysis must be prepared in a matter of weeks.[401]

Sierra Club's proposal to adopt accelerated Exit Dates depends on a mistaken belief that the Company's coal-fired units are "already each uneconomic or marginal on their own[.]"[402] This is incorrect.[403] While the 2019 IRP showed that customers may benefit from the early closure of certain units, it in no way showed that each unit was uneconomic or marginal.[404]

VIII. DECOMMISSIONING

As part of the 2020 Protocol, parties agreed that PacifiCorp would retain a third-party expert to provide estimated decommissioning costs.[405] For coal plants that continue to operate beyond the Oregon Exit Date, Oregon customers will pay only the estimated decommissioning amount, not actual amounts, so the accuracy of the Company's estimates is crucial to ensuring Oregon customers pay a fair share of decommissioning costs.[406] PacifiCorp retained Kiewit Engineering Group, Inc. (Kiewit), an independent third-party with significant experience performing decommissioning and remediation at coal-fired plants.[407] PacifiCorp filed Kiewit's Decommissioning Studies in docket UM 1968, replacing the 2018 decommissioning study in its original filing as a more current, accurate and complete cost estimate.[408]

Staff, CUB, and AWEC argue that the Kiewit Decommissioning Studies are inadequately

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[401] PAC/3800, Link/28. While Sierra Club urges the Commission to require the Company to analyze the future of the Company's coal-fired units in the 2021 IRP, Sierra Club acknowledges that the Company has already committed to perform "just such an analysis" as part of the Company's established IRP process. Sierra Club's Prehearing Brief at 30.

[402] Sierra Club/300, Hausman/17-18.

[403] PAC/3800, Link/2.

[404] PAC/2300, Link/73.

[405] *In the Matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation into Multi-Jurisdictional Issues and Approve an Inter-jurisdictional Cost Allocation Protocol*, Docket UM 1050, Order No. 20-024, Appendix B at 21 (Jan. 23, 2020), (referring to "a contractor-assisted engineering study"); *see also* PAC/3300, Lockey/24; PAC/2400, Van Engelenhoven/11.

[406] PAC/3300, Lockey/24.

[407] PAC/3900, Van Engelenhoven/5.

[408] In a ruling dated April 2, 2020, the Commission expanded the scope of this case to allow adjudication of coal plant depreciation and decommissioning issues in this case instead of docket UM 1968.

supported, and that the Commission should instead adopt the Company's 2018 decommissioning study cost estimates—despite the fact that these earlier estimates were *less* robust and are now known to be understated.[409] Staff and CUB also recommend that the Commission open a separate investigation to consider any further cost changes,[410] though AWEC opposes this recommendation.[411]

The Commission should set rates using the Decommissioning Studies because they are the most up-to-date and accurate cost estimates. In recognition of parties' concerns, however, PacifiCorp also proposes that the Commission open a separate proceeding to allow further review of the Decommissioning Studies, while establishing a tracking mechanism to allow final decommissioning cost estimates to be trued-up to the amounts included in rates in this case.[412]

A. <u>The Decommissioning Studies are more accurate than previous cost estimates.</u>

The Decommissioning Studies were conducted to an Association for the Advancement of Cost Engineering (AACE) Class 3 estimate, which provides the most accurate estimate possible without actually soliciting bids to complete the work.[413] The Studies' cost estimate has an expected accuracy of minus 20 percent to plus 30 percent.[414] The key driver behind the accuracy of a cost estimate is the degree to which the scope of the work is understood; the Decommissioning Studies defined 10-40 percent of the project scope.[415] The Decommissioning Studies estimated the cost and salvage values for each unit individually and all common plant facilities—both inside and outside the facility perimeter.[416] In addition, the Decommissioning

[409] Staff's Prehearing Brief at 12; CUB's Prehearing Brief at 19; AWEC's Prehearing Brief at 17.
[410] Staff's Prehearing Brief at 12; CUB's Prehearing Brief at 19.
[411] AWEC's Prehearing Brief at 17.
[412] PAC/3300, Lockey/24.
[413] PAC/2400, Van Engelenhoven/12.
[414] PAC/1703, Teply/5.
[415] Tr. 188:13-189:24; PAC/3900, Van Engelenhoven/10.
[416] PAC/1703, Teply/6.

Studies cover reclamation costs[417] and owner's project development and oversight costs, including the cost of preparing the facility for the work, project management, long-lead permitting, and site demolition management.[418]

The previous decommissioning cost estimates filed in docket UM 1968, in contrast, were extrapolated from AACE Class 5 estimates, which have an expected accuracy of minus 50 percent to plus 100 percent.[419] The prior studies defined 0-2 percent of the project scope.[420] The prior estimates were less accurate because they were not based on site-specific studies. Instead, the previous estimates developed demolition costs and salvage values for three plants that were intended to be generally representative of the entire fleet.[421] The cost of demolition and salvage for the plants that were not directly studied were extrapolated to establish estimates. The prior studies were focused primarily at the plant level and did not include infrastructure outside the perimeter.[422] The previous estimates did not include site reclamation or owner's costs.[423]

Staff and CUB urge the Commission to decline to accept the Decommissioning Studies until after a separate investigation.[424] Delaying adopting the more accurate estimates would lead to more rate volatility as customers would have a shorter period over which to recover the increased decommissioning costs. As Staff recognizes, "determining appropriate decommissioning costs for Oregon as soon as practicable is paramount due to the relatively short

[417] Reclamation scope assumptions include grading to meet permit conditions and match existing terrain as much as reasonably possible, installing topsoil, and seeding for native plants. PAC/1703, Teply/7.
[418] PAC/1703, Teply/7-8.
[419] PAC/1703, Teply/5.
[420] Sept. 9, 2020, Tr. 188:13-189:24.
[421] PAC/1703, Teply/6.
[422] PAC/1703, Teply/6.
[423] PAC/1703, Teply/7.
[424] CUB's Prehearing Brief at 18-19; Staff's Prehearing Brief at 12. Note, all parties have agreed to defer consideration of CUB's proposal, which would incorporate decommissioning costs through a non-bypassable charge for direct access customers, to docket UM 2024. CUB's Prehearing Brief at 19.

timeframe in which to collect these costs."[425] The Commission should reject AWEC's proposal to set final decommissioning costs using the demonstrably less accurate 2018 studies.[426]

B. PacifiCorp's decommissioning costs are supported by substantial evidence.

"Substantial evidence exists to support a finding of fact when the record, viewed as a whole, would permit a reasonable person to make that finding."[427] To meet this standard, the Commission can rely exclusively on an expert's testimony and study reports.[428] CUB and AWEC claim that the record supporting PacifiCorp's proposed decommissioning costs is inadequate.[429] Indeed, AWEC argues that the Decommissioning Studies and PacifiCorp's testimony are legally insufficient to uphold a Commission decision incorporating the decommissioning cost estimates into rates, pointing to *Calpine Energy* and *WaterWatch*.[430] These arguments understate the robust record in this case and misconstrue Oregon court precedent. In *Calpine Energy*, the Court of Appeals concluded that *no testimony* supported the Commission's factual finding and that the record contained no "calculation or explanation" of the Commission's stated facts.[431] In *WaterWatch*, the Court of Appeals concluded that an agency finding lacked sufficient evidence because it was based on a one-line conclusion from an agency

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[425] Staff's Prehearing Brief at 13.
[426] AWEC's Prehearing Brief at 17-18.
[427] ORS 183.482(8)(c).
[428] *BWK, Inv. v. Dept. of Admin. Servs.*, 231 Or App 214, 229 (2009); *see also Gambee v. Or. Med. Bd.*, 261 Or App 169, 181 (2014) ("When viewing the record as a whole, we conclude that substantial evidence—in this case, expert testimony—supports the board's finding[.]"); *Friends of Parrett Mt., v. Nw. Nat. Gas Co. (In re Site Certificate for S. Mist Pipeline Extension)*, 336 Or 93, 105-106 (2003) ("In making [a] determination [of substantial evidence], the probative weight to be accorded the testimony of expert witnesses is for the trier of fact to apportion."); *Save Our Rural Or. v. Energy Facility Siting Council*, 339 Or 353, 380-81 (2005) (concluding that EFSC's finding that a proposed land use would not substantially impact surrounding lands was supported by substantial evidence, though the finding relied exclusively on expert testimony regarding the adequacy of a proposed mitigation plan and acreage buffer).
[429] AWEC's Prehearing Brief at 16; CUB's Prehearing Brief at 18 ("The administrative record on this issue is sparse[.]").
[430] AWEC's Prehearing Brief at 16 (citing *Calpine Energy Sols. LLC v. PUC of Or.,* 298 Or App 143 (2019) and *WaterWatch of Oregon, Inc. v. Water Resources Dept.*, 268 Or App 187, 218 (2014)).
[431] *Calpine Energy*, 298 Or App at 160.

expert that lacked any explanation or analysis.[432]

Here, in contrast, PacifiCorp has supported its proposed decommissioning cost estimates with both a rigorous third-party report and the expert testimony of PacifiCorp witness Mr. Bob Van Engelenhoven, who explains that Kiewit's Decommissioning Studies are consistent with industry standard and provide a reliable basis for estimating actual decommissioning costs.[433] Far from the "bare conclusions by agency experts" described by AWEC, the record in this case clearly supports a conclusion that Kiewit's Decommissioning Studies are the most accurate available estimate of the Company's likely decommissioning costs for its coal-fired facilities.[434]

Staff, AWEC, and CUB claim that the Commission should not approve the Decommissioning Studies because Kiewit was unwilling to provide its proprietary workpapers.[435] However, this emphasis on workpapers ignores the substantial detail already provided in Kiewit's reports. The reports explain how Kiewit arrived at its decommissioning estimates, including providing detailed maps, itemized costs, detailed scope of work, and discussion of various cost estimates.[436] For instance, for salvageable materials, Kiewit explained how it arrived at the amounts of different types of salvageable metals, how different types of metals were priced, and the ability to dispose of each type—accounting for tipping fees, trucking costs, and other extensive detail.[437] As a general matter, the details sought by parties are *already in Kiewit's report*.

AWEC claims that the Kiewit report is unreliable because it includes estimates out to a

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[432] *WaterWatch*, 268 Or App at 218 (concluding that the agency's finding was unsupported because the record did not define key statements, and the only support on the record was a one-line conclusion that another expert's testimony "does not provide information that would alter [the Department's] assessment").
[433] PAC/2400, Van Engelenhoven/12.
[434] AWEC's Prehearing Brief at 16.
[435] Staff's Prehearing Brief at 14; CUB/300, Jenks/4; AWEC's Prehearing Brief at 14.
[436] Sept. 9, 2020, Tr. 183:21-184:9.
[437] Sept. 9, 2020, Tr. 184:10-185:5.

specific dollar amount.[438] The precision of a number is not a logical basis for assuming the estimate is incorrect.[439]

Staff, AWEC, and CUB argue that Kiewit's studies are unreliable because PacifiCorp provided certain factual inputs to Kiewit.[440] PacifiCorp provided two basic categories of information to Kiewit: (1) the Asset Retirement Obligation for each plant, with asbestos removal identified and separated; and (2) owner's costs—including labor, engineering fees, and similar costs that PacifiCorp was in the best position to provide.[441] While PacifiCorp provided these background materials, Kiewit was nonetheless responsible for determining what cost estimates to adopt or replace in its expert report.[442] And owner's costs were excluded altogether from the earlier decommissioning studies that AWEC claims are more accurate.

Staff incorrectly claims that PacifiCorp actively withheld information from Staff, other parties, and the IE.[443] As PacifiCorp previously explained, Staff negotiated an agreement with the IE that did not *allow* the IE to discuss the Decommissioning Studies with the Company.[444] Had the IE been permitted to communicate with the Company directly, much of the IE's confusion could have been ameliorated.[445] PacifiCorp has worked diligently to provide requested information to Staff and parties in a timely manner.

C. <u>The IE's Report misunderstood the Decommissioning Studies.</u>

Staff, CUB, and AWEC further argue that the Commission should reject the Company's Decommissioning Studies because the IE Report did not support their acceptance.[446] However,

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438 AWEC's Prehearing Brief at 15.
439 Sept. 9, 2020, Tr. 185:6-20.
440 Staff's Prehearing Brief at 14; CUB/300, Jenks/4; AWEC's Prehearing Brief at 15.
441 PAC/3900, Van Engelenhoven/16.
442 Sept. 9, 2020, Tr. 180:2-9.
443 Staff's Prehearing Brief at 14.
444 PAC/3900, Van Engelenhoven/4.
445 PAC/3900, Van Engelenhoven/5.
446 Staff's Prehearing Brief at 14; CUB's Prehearing Brief at 18-19; AWEC's Prehearing Brief at 15.

the IE's report appears to have been based on several misunderstandings.

First, the IE misunderstood the information that was supplied by PacifiCorp to Kiewit to perform the Decommissioning Studies, perhaps in part because, as noted above, the IE was prevented from discussing the Decommissioning Studies with the Company.[447] Unfortunately, because of the constraints on the IE's review and a misunderstanding of certain data, the IE's review focused on the process of developing the Decommissioning Studies rather than the estimated decommissioning costs.[448]

Second, the IE made its review contingent on [redacted][449] despite the fact that such limitations should not have been surprising to someone familiar with the competitive dynamics of the industry.[450] Kiewit understandably declined to provide its workpapers, given the clear competitive disadvantage that could accompany the disclosure of such proprietary information.[451]

Third, the IE appears to have overlooked its own responsibility to "prepare and deliver" an alternate, independent AACE Class 3 estimate.[452] The IE should not have needed any of Kiewit's underlying data to prepare its own cost estimates based on its own independent experience and judgment.

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[447] PAC/3900, Van Engelenhoven/4; Staff/1701 Storm/4 (IE Report) (describing the IE's statement of work, which "did not include site visits to the different plants nor discussions with PacifiCorp and its contractors," and "did not include the ability to independently review and evaluate materials that were not already included in the studies").
[448] PAC/3900, Van Engelenhoven/4.
[449] Staff/1701, Storm/6 (IE Report).
[450] PAC/3900, Van Engelenhoven/5.
[451] PAC/3900, Van Engelenhoven/7; *see also* PAC/3901 (PacifiCorp's email correspondence with Kiewit representatives).
[452] Docket UE 374, Staff Report, Attachment C at 16.

IX. TRANSMISSION

A. Staff's transmission classification adjustments are unsupported by substantial evidence and reason, and are contrary to Commission law and precedent.

Staff recommends disallowances related to the Goshen-Sugarmill-Rigby and SW Wyoming Silver Creek projects and various smaller out-of-state projects because Staff claims that PacifiCorp has not demonstrated that the projects are properly classified as transmission assets.[453] The scope and basis for Staff's proposed disallowance is unclear and, as Staff now appears to acknowledge, the adjustment is contrary to the 2020 Protocol. While the Company carries the initial burden to demonstrate that its costs are reasonable and prudent, parties proposing disallowances must present evidence to support their proposed adjustments.[454] Here, Staff fails to meet this standard by seeking to remove reasonable and necessary costs and to reduce Company's revenue requirement without any rational or legal basis.

1. Under the 2020 Protocol, PacifiCorp's Open Access Transmission Tariff (OATT) determines whether a transmission asset is allocated to Oregon, and the OATT classifies all the disputed assets as transmission.

The Commission approved the 2020 Protocol in Order No. 20-024,[455] and Staff agrees that it governs the allocation of inter-jurisdictional costs in this case.[456] The 2020 Protocol "maintains the status quo allocation, with existing and new generation and transmission resources (online before 2024) treated as system resources and allocated to Oregon based on our use of the PacifiCorp system."[457]

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[453] Staff's Prehearing Brief at 24-25. While Staff's Prehearing Brief does not mention its proposed disallowances for the Lassen substation and the State Prison at Salt Lake City, Staff appears to have subsumed these adjustments into its broader proposed disallowance of pro forma projects. Staff's Prehearing Brief at 27 n.103; *see also* Staff/2100, Hanhan-Rashid-Muldoon/26 (proposing adjustments). However, PacifiCorp has already removed the Lassen substation project from its rate request because this project's in-service date has been delayed. PAC/4400, McCoy/7.

[454] Order No. 01-787 at 7 (quoting Order No. 99-697 (Nov. 12, 1999)) (party must present an evidentiary basis to "show that the costs are not reasonable").

[455] Order No. 20-024.

[456] Sept. 9, 2020, Tr. 92:10-23.

[457] Order No. 20-024 at 5.

Staff agrees that the "OATT determines which assets are functionalized as transmission and allocated to Oregon consistent with the 2020 Protocol" and that assets provide a system benefit to Oregon customers if they are appropriately classified as transmission assets by FERC.[458] Staff "is not advocating that an instrument other than the OATT be used to determine whether an asset over which FERC has asserted jurisdiction is appropriately functionalized as transmission, unless and until that asset is reclassified in appropriate proceedings."[459] Staff agrees that the "appropriate proceedings" to reclassify assets occur at FERC, not the Commission.[460]

PacifiCorp's OATT defines its "Transmission System" as all facilities "generally operated at a voltage greater than 34.5 kV" that PacifiCorp uses to provide FERC-jurisdictional transmission service and that are included in PacifiCorp's FERC-jurisdictional transmission revenue requirement.[461] All the assets subject to Staff's proposed disallowance operate above 34.5 kV, are used to provide FERC-jurisdictional transmission service, and are, or will soon be, included in PacifiCorp's FERC-jurisdictional transmission rates.[462] At hearing, Staff confirmed that the "OATT is pointed to by the 2020 Protocol, . . . and the OATT says that these assets that are treated as transmission, [and] are cost allocated" on a system-wide basis.[463] Therefore, under the 2020 Protocol, the disputed projects *must* be allocated on a system basis. Staff's concessions through discovery and at hearing remove any basis for its classification disallowance.

In its prehearing brief, Staff claims to be "troubled" by the fact that PacifiCorp's OATT classifies transmission assets based on voltage, arguing that this is "inconsistent" with FERC

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[458] PAC/4501 at 2, 7, and 16.
[459] PAC/4501 at 5.
[460] Staff's Prehearing Brief at 27; PAC/4502 at 6.
[461] PAC/4500; PAC/4200, Vail/42.
[462] PAC/4200, Vail/43.
[463] Sept. 9, 2020, Tr. 103:24-104:2.

precedent,[464] despite the fact that the allegedly troubling language is in PacifiCorp's OATT because FERC approved it. Unless and until FERC approves a different classification for PacifiCorp, the existing allocation of transmission assets under the 2020 Protocol controls.[465]

2. Staff's adjustment undermines the 2020 Protocol.

Staff agrees that "if its intent was to no longer rely on the OATT" to classify transmission assets "until otherwise reclassified," then Staff "would have been obligated to raise this issue in the Company's Multi-State Process (MSP) discussions and negotiations."[466] But Staff's classification adjustment does just that—Staff recommends a disallowance to assets that are classified as transmission under the OATT *before they are reclassified*. Staff's adjustment therefore departs from the terms of the 2020 Protocol and undermines the considerable effort by stakeholders across PacifiCorp's service area to reach a consensus to fairly allocate costs. When approving the 2020 Protocol, the Commission approached it "with the foundational principle that we value agreement among PacifiCorp's states in the context of an allocation agreement."[467] Staff's proposed adjustment threatens that foundational principle.

Although the 2020 Protocol provides for the possibility of reclassification of transmission assets, that process must occur first, before ratemaking.[468] Staff's position reverses the required order by preemptively reclassifying certain assets for purposes of ratemaking *before* FERC actually reclassifies the assets.[469] Staff's adjustment would effectively freeze cost recovery of out-of-state transmission investments during the reclassification process even though

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[464] Staff's Prehearing Brief at 24.
[465] *In the Matter of Portland Gen. Elec. Co. Application for Support for Reclassification of Plant in Service*, Docket UM 2031, Order No. 19-400 at 3 (Nov. 21, 2019) ("Whether facilities are used in transmission is a question of fact to be decided by FERC"); PAC/4502 at 6 ("Whether facilities are properly classified as transmission facilities for purposes of ratemaking is ultimately a question for FERC.").
[466] PAC/4501 at 17.
[467] Order No. 20-024 at 3.
[468] Order No. 19-400 at 3; PAC/4507 at 22; PAC/4502 at 4-5.
[469] Order No. 19-400 at 3.

reclassification could take years. The fact that Staff agrees that the depreciation costs of these assets could be tracked in a deferral does not negate the fact that Staff is improperly proposing to remove these assets from rates now in advance of any reclassification process.[470]

3. Staff's adjustment is unprecedented and contrary to the Commission's rules.

Staff could not identify any precedent for its classification adjustment, and its witnesses acknowledged that "frankly, . . . it really wasn't until late in the case that we understood" how "PacifiCorp does treat transmission and has for the last 30 years."[471] The 2020 Protocol, and its predecessors, were intended to prevent precisely this type of dispute in general rate cases. Staff also failed to square its recommended disallowance with the Commission's unbundling rules, which generally mirror the OATT and require PacifiCorp's unbundled transmission rates to include assets operating at voltages of at least 46 kV.[472]

4. Staff's adjustment is one-sided.

Staff applies its proposed reclassification disallowance to only those transmission assets located outside Oregon.[473] Staff therefore excludes costs from Oregon rates but fails to consider symmetrical reclassification of assets located in Oregon, which could potentially increase Oregon rates. For example, Staff admitted that it never analyzed the Northeast Portland transmission project to determine whether those assets should be situs assigned to Oregon even though several components of the project are below Staff's 100 kV bright line threshold for transmission assets.[474] Had Staff evenhandedly applied its adjustment, there could have been offsetting increases to Oregon rates. Staff also admitted it proposed no change to the transmission revenue credit Oregon customers would receive (i.e., wheeling revenue)—meaning

[470] Staff's Prehearing Brief at 19-20.
[471] *See* PAC/4501 at 1, 3; Sept. 9, 2020, Tr. 110:6-11.
[472] OAR 860-038-0200(9)(a)(C).
[473] *See, e.g.,* Staff/2100, Hanhan-Rashid-Muldoon/49.
[474] Sept. 9, 2020, Tr. 111:22-112:9; PAC/1000, Vail/47-48; Staff/2100 at 47; PAC/4501 at 13.

Oregon would receive windfall revenue credits for assets not in rates.[475]

B. Staff's transmission investigation should be addressed through the MSP.

Staff's testimony and Prehearing Brief recommend that the Commission open a generic investigation "into PacifiCorp's classification of transmission assets."[476] At hearing, Staff could not clearly articulate the purpose of this proposed investigation and was hesitant to even acknowledge it would address classification.[477] Staff also recognized in briefing the limited utility of any investigation, stating: "Given FERC's authority to classify transmission assets, the result of [Staff's proposed] investigation would likely not result in changing the classification of any resource."[478] However, Staff then refused to confirm this same statement at hearing.[479] Given the lack of clarity and the fact that such an investigation would necessarily cover cost allocation issues that are also a part of the ongoing MSP, PacifiCorp recommends that any potential reclassification of transmission assets be addressed through the MSP, rather than in an Oregon-only investigation.

The 2020 Protocol provides for a process for reclassifying transmission and distribution assets and requires filings in every state, not just Oregon.[480] This means that if Oregon embarks on a reclassification investigation, other states may be compelled to do so too. It is likely that stakeholders in other states would have an interest in potential reclassification because changing an asset from transmission to distribution affects whether the asset is system allocated or situs assigned. To the extent a current transmission asset is reclassified as a distribution asset (as Staff proposed in this case), that reclassification will shift costs from Oregon to the state where the

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[475] PAC/4501 at 6, 16.
[476] Staff's Prehearing Brief at 27.
[477] Sept. 9, 2020, Tr. 114:6-16, 122:1-123:14.
[478] Staff's Prehearing Brief at 27.
[479] Sept. 9, 2020, Tr. 98:5-8.
[480] PAC/4507 at 22.

asset is located and vice versa.

Addressing the issue in the MSP first will mitigate the risk that different states will make different classifications. Staff agrees that reclassification typically requires a utility to go first to the state commission and then to FERC.[481] PacifiCorp will be required to go to six states before FERC. And it is quite possible that not every state will agree on the proper classification of assets, particularly because of the potential to shift costs among the states. If there is no agreement, the states will presumably have to litigate their preferred reclassifications before FERC, which makes the ultimate decision.[482] Although FERC will defer to some extent to state commissions, it is unlikely that FERC would defer to Oregon's determination of another state's jurisdiction. For example, if Oregon decides that Utah has jurisdiction over certain facilities in Utah because they are distribution assets and Utah concludes it does not have jurisdiction because they are transmission assets, FERC is unlikely to defer to Oregon's determination of Utah's jurisdiction. If reclassification is addressed in the MSP first, with the broad array of stakeholders from across PacifiCorp's service area, it is possible that consensus could be achieved and litigation at FERC could be avoided.

C. **Staff's adjustments for transmission cost increases are plainly unsupported.**

Staff asks the Commission to disallow certain cost increases at the Wallula to McNary, Vantage to Pomona Heights, and Threemile Canyon Farm projects, and at the pro forma[483] Pryor Mountain project.[484] Staff describes cost increases at these projects as "overruns" on the basis

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[481] PAC/4502 at 4-5.
[482] *See* Order No. 19-400 at 3.
[483] Staff's Prehearing Brief refers to the pro forma Pavant transformer project in one instance (page 22) and to the Q0542 Pryor Mountain pro forma project in another instance (page 27), and seems to conflate the two by referring to a single pro forma project (page 22). PacifiCorp already accepted Staff's adjustment at the Pavant transformer project because that project experienced a cost *decrease* in the amount identified by Staff—not a cost overrun. PAC/4200, Vail/21.
[484] Staff's Prehearing Brief at 22. Note, Staff's Prehearing Brief refers to the SW Wyoming Silver Creek project as

that the ultimate project costs were higher than the projects' original budget forecasts.[485]

The Commission does not disallow prudently incurred costs merely because those costs increase from forecast estimates.[486] As the Commission has explained, "all construction projects inevitably involve some difficulties," and prudently incurred cost increases beyond the Company's control remain part of the reasonable cost of providing service.[487] PacifiCorp witness Mr. Rick Vail testified in detail concerning how project budgets are developed and the basis for the cost increases at each of the projects identified by Staff.[488] As Mr. Vail explained, project budgets are necessarily estimates that are gradually refined to reflect on-the-ground realities.[489] For the identified projects, costs changed due to external events that PacifiCorp could neither control nor reasonably foresee, such as COVID-19, government shut-downs, increased labor costs, unexpected weather conditions, and a protected bird of prey creating a new nest within a project area.[490]

The cost change associated with the Wallula to McNary line was primarily due to changes in the construction schedule caused by weather conditions and delays caused by uncertainty surrounding the third-party transmission service requests that contributed to the need for the line.[491] PacifiCorp prudently responded to these changed circumstances, however, and fulfilled its obligations under the OATT to provide transmission service. Moving forward in the face of uncertainty surrounding the project need, as Staff implies a prudent utility would have

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entailing a cost overrun. This is incorrect. As Staff's testimony (Staff/2100, Hanhan/Rashid/Muldoon/33-34) and other parts of Staff's Prehearing Brief (page 27) make clear, Staff includes SW Wyoming Silver Creek as part of the category of projects that Staff would wholly disallow due to transmission/distribution categorization concerns.

[485] Staff/2100, Hanhan/Rashid/Muldoon/29 (comparing the estimated final costs to "the original budget").

[486] Order No. 01-988 at 5.

[487] Order No. 99-697 at 52.

[488] PAC/4200, Vail/6-21.

[489] PAC/4200, Vail/6.

[490] PAC/4200, Vail/7.

[491] PAC/4200, Vail/13-15.

done to ensure costs remained in line with estimates, is unreasonable.

The cost change for the Vantage to Pomona Heights project was associated largely with changes to the line's route that occurred as the project progressed through the permitting, right-of-way, and federal requirements to construct the line.[492] Costs also increased because of permitting delays, increased labor costs, and a falcon nest—all of which were outside the Company's control. Staff neither acknowledges these factors nor provides evidence that the Company imprudently responded to changed circumstances. Instead, Staff simplistically compared a preliminary cost estimate based on a planner's route to the final cost based on actual permitting and construction and then concluded that the difference was due to imprudence.

For its Threemile Canyon Farms adjustment, Staff simply compared a preliminary estimate that was prepared with a +/- 50 percent accuracy to the actual costs based on competitive bids.[493] It is not imprudent to refine an estimate over time or for an initial high-level estimate to be less than the actual costs once the competitive bids were received.

Staff's Pryor Mountain adjustment ignores the significant changes that occurred over the course of that project's development.[494] The interconnection costs increased not because of imprudence but because of OATT-required interconnection restudies caused by changes to the point of interconnection, wind turbines, and project configuration. It is typical for a project's interconnection costs to change over a five-year development period. Staff ignores PacifiCorp's obligations under its OATT and the changes to the project and instead compares cost estimates from two different interconnection studies without accounting for why the cost estimates changed. Staff's adjustment is also irreconcilable with Staff's agreement that the Pryor Mountain

[492] PAC/4200, Vail/9-13.
[493] PAC/4200, Vail/17-18.
[494] PAC/4200, Vail/18-21.

project is prudent.[495]

Staff responded to the Company's testimony on increased transmission costs with the generic statement that "Staff believes that the Company could have been more proactive with respect to the projects at issue to manage the costs."[496] Not only does Staff fail to specify *how* the Company could have further mitigated costs, Staff simultaneously recognizes that certain cost increases "may have been outside of the Company's control"[497] and that "costs for construction will vary."[498] Nonetheless, Staff claims that all unanticipated cost increases should be borne by the Company—seemingly without regard to the prudence of these increased costs.[499] Staff's statement of belief without supporting evidence or analysis cannot support its adjustment.

D. <u>PacifiCorp provided substantial evidence to support its pro forma transmission projects.</u>

Staff also recommends a reduction in revenue requirement of $7.8 million (reflecting a disallowance of $285.2 million) for the majority of the smaller pro forma capital addition projects that were originally described in PAC/1309, because Staff claimed that the projects were "unverifiable."[500] Staff proposed this adjustment for the first time in its rebuttal testimony, arguing that the Company had failed to provide detailed information for each of the pro forma projects.[501] Prior to receiving Staff's rebuttal testimony, PacifiCorp had reasonably anticipated that Staff would apply a sampling approach in its review of the Company's smaller projects, as set forth in Staff's pre-rate case audit report, issued on May 12, 2020. The report stated that

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[495] *See* Staff/800 and Staff/2000.
[496] Staff's Prehearing Brief at 22.
[497] Staff/2100, Hanhan/Rashid/Muldoon/30.
[498] Staff's Prehearing Brief at 22.
[499] Staff's Prehearing Brief at 22.
[500] Staff's Prehearing Brief at 26-27; Attachment A at 2 (Adjustment Appendix). Note, this amount does not include disallowance of the Sams Valley substation or the Phase Wye-Delta XFMR project, as Staff's Prehearing Brief states that it has no adjustment to either project. Staff's Prehearing Brief at 26-27.
[501] Staff/2100, Hanhan-Rashid-Muldoon/42.

"Rate Case staff should consider a stratified sampling approach across FERC accounts, especially for projects greater than $1 million, which are not explicitly discussed in the Company's testimony."[502] Despite the effort expended by Staff to develop a review process in the pre-rate case audit, PacifiCorp's outreach to parties to address discovery issues, and PacifiCorp's provision of project-by-project work orders, contracts, and internal approvals, Staff did not apply the sampling approach in this proceeding or appear to assign any value to the reasonableness of PacifiCorp's decisions based on information available at the time.

In response to Staff's new concerns on rebuttal, PacifiCorp significantly expanded its evidence supporting these smaller projects on surrebuttal. PacifiCorp prepared PAC/4202, which (1) provided details regarding the nature and benefit of each project; (2) identified where project information was provided to Staff in discovery; (3) updated the project's in-service date, where necessary; and (4) provided a narrative explanation for each project over $500,000 on a system-wide basis.[503] Staff's briefing neither acknowledges this evidence nor disputes it. The evidence provided by PacifiCorp demonstrates the prudence of each of these projects and is sufficient to include the costs in rate base.

X. NEW WIND AND ATTESTATIONS

This rate case includes approximately 1,400 MW of new wind investments, including the EV 2020 New Wind projects, repowering of the Foote Creek I wind facility, and the Pryor Mountain Wind Project.[504] For each of these projects, PacifiCorp has agreed with Staff's proposal to provide a Vice President attestation if the project is placed in service between

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[502] Audit Report of PacifiCorp Audit Number 2019-01 (May 12, 2020). Note, while Staff's Audit Report states that sampling is appropriate for projects greater than $1 million, PacifiCorp understands that a similar approach would be at least as applicable for projects under $1 million.
[503] PAC/4200, Vail/39; PAC/4202.
[504] PAC/3300, Lockey/21. CUB initially objected to the Company's recovery of costs for the Pryor Mountain Wind Project (CUB/100, Jenks/55) but has since withdrawn its objection and accepts that the Company has sufficiently supported the prudence of this project. CUB's Prehearing Brief at 19-20

January 1, 2021, and June 30, 2021, and to confer with parties to this proceeding if these projects' commercial operation dates, or that of their necessary transmission infrastructure, extend past June 30, 2021.[505]

A. The Commission should reject AWEC's proposed restrictions on cost recovery for the EV 2020 wind and transmission projects.

While all parties support the prudence of the new wind and related transmission investments, AWEC recommends that the Commission restrict cost recovery for the Company's EV 2020 wind and transmission projects (collectively, Combined Projects) by imposing (1) a hard cap on capital and O&M costs based on the bids submitted in the request for proposals (RFP), (2) a hard cap on transmission costs based on the RFP projections, (3) a guarantee of full PTC benefits, and (4) a guaranteed minimum capacity factor based on the level of the modeled bids.[506] However, AWEC allows that investments to enhance maintenance activities that could increase wind energy output would be recoverable "if the Company can demonstrate a net benefit to customers from incremental investments or maintenance in the future."[507] AWEC argues that these limitations on recovery are appropriate because the EV 2020 projects were not intended to "meet an energy or capacity need," because the Oregon IE recommended similar conditions, and because in the 2017R RFP the Commission suggested that it may impose similar conditions.[508]

First, the Company's testimony demonstrated that the EV 2020 projects meet a projected energy and capacity need and therefore are no different from any other resource acquisition identified in an IRP.[509] AWEC did not rebut the Company's evidence.

[505] Staff/2000, Storm/3.
[506] AWEC's Prehearing Brief at 24.
[507] AWEC's Prehearing Brief at 26-27.
[508] AWEC's Prehearing Brief at 24; AWEC/100, Mullins/14.
[509] PAC/2300, Link/54.

Second, by imposing caps on individual cost components without regard to whether the overall project costs and benefits are affected, AWEC's conditions are unnecessarily punitive. For example, while capital costs increased, that increase was offset by lower O&M costs.[510] But under AWEC's recommendations, those offsetting changes would be ignored, and the Company would under-recover prudently incurred capital costs, while customers would benefit from the lower O&M expense. AWEC's recommendations are also one-sided and would require the Company to pass through increased benefits while disallowing recovery of the costs incurred to produce those benefits. Adopting AWEC's recommendations would create a disincentive for future investment in renewable resources.

Third, the Commission did not decide in the 2017 IRP to impose conditions like those AWEC recommends,[511] and indeed already concluded that the 2020 TAM stipulation satisfied the standard set in the 2017 IRP order.[512] The Commission merely indicated that it "may" impose conditions intended to ensure customer benefits. Based on events that have occurred since the 2017 IRP, the Company has demonstrated that, even though certain cost components have increased, the overall expected customer benefits remain. Moreover, as is clear from the rate decrease proposed in the 2021 TAM, the benefits of the EV 2020 wind projects are substantial and offset the project costs reflected in this case. Limitations on cost recovery for these prudent projects are therefore unnecessary.

Fourth, there were no irregularities in the 2017R RFP that warrant limitations on recovery of prudently incurred costs. The Oregon IE confirmed that the EV 2020 projects were the "top viable offers" given the interconnection constraints and "are projected to provide net benefits."[513]

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[510] PAC/2700, Hemstreet/9-10.
[511] *PacifiCorp's 2017 IRP*, Docket LC 67, Order No. 18-138 at 8 (Apr. 27, 2018).
[512] Order No. 19-351 at 6.
[513] Oregon IE Report at 37, 39.

The Oregon IE agreed that PacifiCorp appropriately accounted for the interconnection constraints: "To go forward with projects that cannot meet the proposed online date without major accelerated transmission investment would not seem to be the wisest course of action."[514] Complaints over PTC modeling or terminal value benefits for utility-owned resources are therefore irrelevant because those modeling assumptions did not actually impact the RFP results.

Finally, AWEC's PTC and capacity factor proposals are inappropriate because the Commission already approved a stipulation in the 2020 TAM addressing capacity factor and PTC modeling for the EV 2020 projects.[515] These issues have already been fully resolved by the Commission.

B. Staff's proposed restrictions on and investigation into Schedule 272 are unnecessary.

Staff proposes to restrict the Company's continued ability to use Schedule 272 to acquire future utility-owned resources like Pryor Mountain, despite agreeing that PacifiCorp was prudent to develop the facility.[516] Specifically, Staff states that it is concerned about potential "disparate treatment between PGE and PacifiCorp" with respect to application of the Voluntary Renewable Energy Tariff guidelines.[517] Staff also clarifies that it seeks a comprehensive investigation of Schedule 272, including the sale of Renewable Energy Credits from utility-owned and power purchase agreement resources.[518]

Staff's proposed restriction and investigation are unnecessary, as PacifiCorp does not anticipate entering into another Schedule 272 agreement involving a utility-owned facility in the

[514] Oregon IE Report at 37.
[515] In the 2020 TAM, the parties stipulated on the capacity factors for EV 2020 projects. In addition, AWEC committed to drop its request for a PTC floor for the EV 2020 projects. *See* Order No. 19-351, Appendix A at 8 ("The parties agree to drop their recommendation for a PTC floor.")
[516] Staff's Prehearing Brief at 48.
[517] Staff's Prehearing Brief at 49.
[518] Staff's Prehearing Brief at 50.

foreseeable future.[519] If the Company is presented with an opportunity to achieve substantial customer benefits involving a utility-owned facility, PacifiCorp agrees that it would meet and confer with stakeholders before proceeding with the transaction.[520] While Staff disputes the adequacy of the Company's commitments "without process and Commission resolution,"[521] there is no need to open another investigatory proceeding to address an issue that has no near-term consequence to customers.

XI. WAGES & INCENTIVES

A. <u>The Commission should apply PacifiCorp's wage escalation for non-union wages.</u>

For non-union employees, PacifiCorp uses several industry-wide surveys to determine the percentage base pay increase.[522] In contrast, Staff proposes to use the All-Urban Consumer Price Index, updated quarterly.[523] Staff claims that its three-year model is appropriate because the Commission has "accepted and used the three-year wages and salary model for over 20 years."[524] While the Commission has previously used Staff's three-year formula for escalating non-union wages, the Commission has also been willing to modify Staff's formula where there is evidence that such a modification would "provide more reliable estimates[.]"[525] Here, PacifiCorp has offered a more reliable means of measuring wage escalation by beginning with actual base period data, and then using a wage- and utility-specific benchmarking study.[526]

B. <u>The Commission should apply contract-based wage increases for union wages.</u>

The Commission has previously rejected Staff's attempt to apply the three-year wage and

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[519] PAC/3800, Link/29.
[520] PAC/3800, Link/29.
[521] Staff's Prehearing Brief at 50.
[522] PAC/4300, Lewis/3.
[523] Staff/2500, Cohen/7.
[524] Staff's Prehearing Brief at 41.
[525] Order No. 01-787 at 40; *see also* Order No. 99-697 at 43 (declining to accept the Company's job classifications that relied on manufacturing or governmental wages that "are not closely related" to utility wages).
[526] PAC/4300, Lewis/4-5.

salary formula union payroll because "this Commission has traditionally accepted changes in union compensation resulting from the collective bargaining process."[527] Consistent with this precedent, PacifiCorp calculated Test Year wages for union employees using actual contracted wage increase percentages, pursuant to the collective bargaining agreements with the Company's unions.[528] In contrast, Staff escalates union employees' salaries using a calendar year average for all unions.[529] Staff's approach is demonstrably less accurate because Staff fails to account for the Company's actual union contracts.[530]

PacifiCorp appropriately applied the contracted wage increases *by union* because these unions vary in size, and different unions experienced different increases at different times.[531] Staff's approach averaged the various union wage increases and applied this percentage to the entirety of the Company's union wages.[532] Staff suggests that, because the Company's and Staff's calculations are within 10 percent of each other, the Commission should simply split the difference.[533] Staff justifies this approach on the basis that it lacked Oregon-specific negotiated union wage increases.[534] However, as explained by PacifiCorp witness Ms. Shelley McCoy, labor is an allocated expense and Oregon's revenue requirement includes an allocation of some portion of labor expenses from across the Company's operations.[535] PacifiCorp provided system-wide union information and contracted-for wage increases as requested by Staff.[536] The Commission should approve PacifiCorp's union wage escalation because it more accurately

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[527] Order No. 99-697 at 43.
[528] PAC/3100, McCoy/9.
[529] Staff/2500, Cohen/2.
[530] PAC/3100, McCoy/12.
[531] PAC/3100, McCoy/11.
[532] Staff/2500, Cohen/3.
[533] Staff/2500, Cohen/3; *see also* PAC/4400, McCoy/31.
[534] Staff's Prehearing Brief at 42.
[535] PAC/4400, McCoy/33.
[536] PAC/4400, McCoy/33.

reflects the Company's actual expected costs.

C. The Commission should approve recovery of employee incentives.

PacifiCorp's incentive pay is a portion of market-level compensation that is placed at risk in order to motivate excellent employee performance.[537] To be clear, the Company's incentive program is not a "bonus,"[538] but instead is structured to provide benefits to customers consistent with Commission precedent.[539] The removal of incentive expense would therefore result in below-market compensation.[540] PacifiCorp's employee incentives are awarded according to six factors: (1) customer service; (2) employee commitment; (3) environmental respect; (4) regulatory integrity; (5) operational excellence; and (6) financial strength.

Staff does not claim that the Company's use of pay-at-risk is imprudent or unreasonable, but rather states that these costs should be "shared" because incentives tied to financial performance benefit PacifiCorp's shareholders.[541] Staff recommends three categories of disallowances: 100 percent of officers' incentives, 50 percent of non-officer incentives "based on non-financial metrics," and 75 percent of non-officer incentives "based on financial performance measures."[542] Yet Staff's categorization does not align with the Company's actual incentive program. All of the incentive compensation in this case is awarded based on the same six customer benefit goals listed above.[543] While one of the six goals is tied to financial strength, this metric benefits customers because a financially strong utility can access low cost debt, which translates into lower rates.[544] Thus, Staff's proposal to wholly disallow officers' incentives

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[537] PAC/4300, Lewis/2.
[538] PAC/4300, Lewis/2.
[539] PAC/4300, Lewis/2.
[540] PAC/4300, Lewis/2.
[541] Staff's Prehearing Brief at 43.
[542] Staff's Prehearing Brief at 43.
[543] PacifiCorp also disagrees that financial health of the Company is of primary benefit to shareholders because customers also benefit from a financially stable Company that can cost-effectively invest to serve its customers.
[544] PAC/4300, Lewis/9.

because they "hinge on meeting shareholders' financial expectations" is in error.[545] Staff's proposal to disallow officer incentives capitalized in plant should be rejected on the same basis.[546]

While the Commission has previously disallowed portions of utilities' incentive programs, it has done so when incentives benefitted "shareholders rather than ratepayers."[547] The Commission has previously indicated that, if a company submits an employee incentive plan "with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement."[548] Here, PacifiCorp's Annual Incentive Plan (AIP) maximizes customer benefits of high-quality employee performance, and should therefore be fully recovered. In 2011, the Washington Commission stated that PacifiCorp's AIP "is an appropriate method of implementing 'incentive-based' compensation," and was "not a bonus or a level of pay in excess of the maximum compensation for a position."[549]

XII. PENSION SETTLEMENTS

PacifiCorp seeks to recover the costs of pension settlement losses, which are costs associated with administering employee pensions.[550] PacifiCorp previously sought deferred accounting treatment for these costs in docket UM 1992, given the difficulty of foreseeing the expense.[551] The Commission denied the Company's request on the basis that such costs were

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[545] Staff's Prehearing Brief at 43.
[546] Staff's Prehearing Brief at 44.
[547] *In the Matter of U.S. West Communications, Inc. Application for an Increase in Revenues*, Docket UT 125, Order No. 97-171, 1997 Ore. PUC Lexis 102 at *173 (May 19, 1997).
[548] Order No. 97-171, 1997 Ore. PUC Lexis 102 at *174. Note, the Commission rescinded Order No. 97-171 in Docket UT 125 et al., Order No. 00-190, at 18 (Apr. 14, 2000), to accommodate settlement on other issues. That same day, it readopted portions of Order No. 97-171 without modification in Docket UT 125 et al., Order No. 00-191, at 112-116 (Apr. 14, 2000), including the section of Order No. 97-171 addressing incentive plans.
[549] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-100749, Order 06, Final Order at 85-86 (Mar. 25, 2011).
[550] PAC/300, Kobliha/29-31.
[551] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans*, Docket UM 1992, Order No. 20-004 at 4 (Jan. 8, 2020).

reasonably foreseeable, and thus did not qualify for deferral.[552] PacifiCorp therefore developed a forecast for Test Year pension settlement expenses for inclusion in rates.[553]

Staff now objects to recovery of pension settlement losses in rates entirely—either in rates or through a pension balancing account—because Staff claims that the Commission's decision in docket UM 1633 means that these costs are simply unrecoverable. Indeed, Staff argues that pension-related costs are restricted to those costs included in Financial Accounting Standards (FAS) 87,[554] and not the settlement gains and losses of FAS 88.[555] Crucially, Staff does not claim that the Company's costs are imprudent or that PacifiCorp's calculations are incorrect.

Staff's characterization of the Commission's precedent is incorrect. At no point has the Commission stated that pension settlement losses are unrecoverable costs.[556] Moreover, Staff ignores docket UM 1992, where the Commission denied PacifiCorp's request to defer settlement losses because they were capable of being forecast, not because settlement losses are unrecoverable in rates.[557] If settlement losses are capable of being forecast and are eligible for rate recovery, then the losses must be built into base rates in a rate case, which is exactly what PacifiCorp has done here.

Staff's assertion that a category of prudently incurred costs should be excluded from rates is inconsistent with the fundamental principle that, under Oregon's cost-of-service paradigm, the

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[552] Order No. 20-004 at 8.
[553] PAC/300, Kobliha/33-35.
[554] FAS 87 is the common term for Financial Accounting Standards Board's Accounting Standards Codification Topic 714-30—Compensation—Retirement Benefits (ASC 715).
[555] Staff/1000, Fox/23; Staff/1800, Fox/17.
[556] *See In the Matter of Pub. Util. Comm'n Of Oregon Investigation into Treatment of Pension Costs in Util. Rates*, Docket UM 1633, Order No. 15-226 at 2 (Aug. 3, 2015) (Commission explained "[o]ver the life of the plan, . . . total contributions are expected to equal total FAS 87 expense (*as well as FAS 88 expense* related to pension plan termination)" and did not preclude cost recovery of FAS 88 expense).
[557] Order No. 20-004 at 8-9.

Commission "must allow a utility the opportunity to recover increased operating expenses that are prudently incurred."[558] Pension settlement losses should be included in rates as they are a valid cost of providing a pension plan.[559] Alternately, the Commission could reconsider the Company's request to create a deferral or balancing account for prospective pension costs, including settlement costs.[560]

XIII. DEER CREEK MINE CLOSURE

PacifiCorp requests that the Commission grant recovery of the costs to close the Deer Creek coal mine and amortize the Deer Creek mine deferred account into rate base over three years.[561] No party contests the prudence of PacifiCorp's decision to close the mine, and only AWEC challenges the prudence of the Company's mine closure costs.

A. <u>The Commission should allow full cost recovery of the Company's costs to close the Deer Creek mine.</u>

AWEC proposes to disallow approximately $[redacted] of Deer Creek mine closure costs because the Company's costs exceeded the cost estimate provided in docket UM 1712, which established the Deer Creek mine deferral.[562] While certain closure costs were higher than expected, the overall costs to close the mine increased by only $[redacted] or [redacted] from the Company's estimate because the Company was able to avoid the assessment of a coal abandonment royalty penalty.

Moreover, the closure costs that did increase were prudent. AWEC argues that PacifiCorp has failed to justify the increased costs associated with regulatory delays because (1) the Company's initial bulkhead application was denied; and (2) the Company did not detail the

[558] Order No. 01-988 at 5.
[559] PAC/3400, Kobliha/17.
[560] PAC/3400, Kobliha/17.
[561] PAC/4100, Ralston/17; PAC/3100, McCoy/42; PAC/1300, McCoy/9.
[562] AWEC's Prehearing Brief at 38.

specific cost components tied to maintaining the Deer Creek mine in a safe condition pending closure.[563] First, while the initial application was disapproved, the Mine Safety and Health Administration's (MSHA) requested additional information and analysis. The Company provided a revised application within approximately two months of the MSHA decision, and therefore this initial denial did not cause the extreme delay the Company experienced.[564] The delay was caused by regulatory upheaval following the Gold King mine spill.[565] PacifiCorp could not have anticipated that the Company's application process would coincide with a third-party's mine spill and state agencies' resulting reevaluation of appropriate methods for mine closure.

Second, PacifiCorp provided sufficient evidence supporting the reasonableness of its increased costs. As PacifiCorp witness Mr. Dana Ralston explained, the protracted regulatory approval process extended the mine's idling period by 21 months, which entailed ongoing third-party contracting costs to safely maintain the mine as required by MSHA before closure.[566] Notably, PacifiCorp previously clarified that the third-party contractor retained to complete the idling work at the Deer Creek mine, East Mountain Energy, is not affiliated with PacifiCorp and is an independent contractor with a United Mine Workers of America affiliation.[567] AWEC stubbornly refuses to accept this fact and continues to erroneously claim that PacifiCorp's costs were paid "to the PacifiCorp subsidiary East Mountain Energy."[568]

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[563] AWEC's Prehearing Brief at 38-40.
[564] PAC/4100, Ralston/19.
[565] PAC/4100, Ralston/19; *see also* AWEC/705. This upheaval included the MSHA's decision declining to consider the Company's second application, then disclaiming jurisdictional authority over the mine closure entirely, and finally, the Utah Division of Oil, Gas and Mining's (DOGM) decision concluding that the proposed closure method was prohibited entirely
[566] PAC/4100, Ralston/20.
[567] PAC/4100, Ralston/20.
[568] AWEC's Prehearing Brief at 40.

B. <u>The Commission should approve recovery of royalty payments because the Company has provided a reliable forecast</u>

AWEC recommends royalty payments associated with the Deer Creek mine be excluded from this rate case because they are based on a forecast, and therefore are not "known and measurable."[569] A significant portion of the royalty costs have already been incurred.[570] In addition, AWEC misstates the Commission's standard for including costs in the prospective test year. As the Commission explained in Order No. 00-191, quoted by AWEC, this Commission does not use the "known and measurable" standard:

> The 'reasonably certain' standard, rather than the 'known and measurable' standard, is the correct one for judging whether a given adjustment is appropriate. *That standard does not preclude forecasts*.[571]

Here, mine royalties are a necessary part of mine closure costs, and should be appropriately included in rates at the forecast amount.[572] AWEC does not specifically object to the *amount* of the Company's forecast, merely to the fact that the costs based on a forecast.[573] If the Commission declines to include royalty costs in this rate case, then PacifiCorp will continue to defer them as approved in docket UM 1712, and requests the ability to seek recovery for these costs in a future rate proceeding.[574] AWEC does not object to this alternative proposal.[575]

XIV. OREGON CORPORATE ACTIVITY TAX

The Oregon Corporate Activity Tax (OCAT) is a new state-wide tax on Oregon-sourced commercial activity, and applies to tax years beginning on or after January 1, 2020.[576] Pursuant

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[569] AWEC's Prehearing Brief at 41.
[570] Exhibit PAC/4102, Ralston/1.
[571] *In the Matter of the Application of US West Communications, Inc. for an Increase in Revenues*, Dockets UT 125/UT 80, Order No. 00-191 at 15 (Apr. 14, 2000) (emphasis added).
[572] PAC/4400, McCoy/20-21.
[573] AWEC's Prehearing Brief at 41.
[574] PAC/4400, McCoy/21.
[575] AWEC's Prehearing Brief at 41.
[576] PAC/3100, McCoy/29.

to Commission Order No. 20-028, PacifiCorp has established a balancing account for the OCAT, which tracks and defers the variance between the revenues collected and the actual OCAT expense. In its deferral filing, PacifiCorp explained that significant uncertainties in the implementation of the OCAT would need to be resolved prior to including the OCAT in base rates, such as how to apply the numerous exclusions from the definition of commercial activity.[577] Staff supported PacifiCorp's request and recommended that OCAT "be included in base rates at a future date to be agreed upon by the parties."[578] The Commission approved the OCAT balancing account in Order No. 20-028, which was issued 12 days before PacifiCorp filed this case.

The uncertainties that prompted the Commission to approve the OCAT balancing account remain. The rules for implementing the OCAT are still in progress before the Oregon Department of Revenue (DOR). Indeed, the DOR has not yet finalized the form of the tax return and technical corrections are still anticipated to be presented to the legislature for consideration.[579] Therefore, the Company proposes to continue deferring the difference between collected revenues and actual OCAT expense for future inclusion in rates. In the alternative, PacifiCorp recommends that the Commission permit the Company to defer and true-up any variances between forecast and actual costs for future ratemaking treatment.

Staff opposes both of the Company's proposals and urges the Commission to include $5.2 million of OCAT expense in base rates.[580] Staff states that there is "sufficient certainty" to conclude that this amount is fair, just, and reasonable, consistent with "other applicable taxes."[581]

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[577] *In the Matter of PacifiCorp dba Pacific Power Application for Deferral of Costs and Revenues Related to the Payment and Collection of Oregon's Corp. Activity Tax*, Docket UM 2036, Order No. 20-028, Appendix A at 4 (Jan. 29, 2020).
[578] Order No. 20-028, Appendix A at 6.
[579] PAC/3100, McCoy/30.
[580] Staff's Prehearing Brief at 58.
[581] Staff's Prehearing Brief at 5-59.

However, as noted above, the implementation of the OCAT is still in progress and the degree of certainty has not changed significantly since the Commission approved the OCAT balancing account earlier this year. Therefore, the Company continues to recommend the ongoing use of a separate tariff and balancing account, ensuring that customers are neither under- nor over-charged for this new tax.

XV. ADVANCED METERING INFRASTRUCTURE

The Oregon AMI Project consisted of the on-site replacement of approximately 627,000 customer meters with AMI technology, as well as installation of AMI-related technology and telecommunications infrastructure.[582] No party objects to the prudence of the Company's AMI investment, but Staff and AWEC present two proposed adjustments.

Staff claims that PacifiCorp has understated AMI benefits based on the mistaken belief that the Company failed to account for a $1.2 million reduction in capital costs that was avoided because of AMI.[583] Staff insists that the Company has not demonstrated that the $1.2 million in avoided capital has been excluded and proposes to reduce the Company's revenue requirement by $8.7 million—$2.0 million more than the Company's revenue requirement adjustment of $6.7 million.[584]

This adjustment is both illogical and inappropriate. Customers have *already received* the benefit of the $1.2 million in avoided capital because it was never included in the Company's revenue requirement in the first place.[585] Staff's approach would functionally double count this

[582] PAC/1100, Lucas/23.
[583] Staff/1800, Fox/8. Staff's Prehearing Brief describes Staff's adjustment as an $8.7 million reduction in revenue requirement, rather than as an $8.7 million reduction in expenses. PacifiCorp's proposed revenue requirement reduction is $6.7 million, not $6.5 million as Staff states in its brief. Staff's Prehearing Brief at 57.
[584] Staff's Prehearing Brief at 57.
[585] PacifiCorp explained that this $1.2 million was not included in the Company's actual plant balance as of June 30, 2019, or as a pro forma capital addition, because the project was already nearing completion as the Company prepared this rate case. PAC/4400, McCoy/9.

$1.2 million benefit. In addition, it is entirely baseless to propose a $2 million revenue requirement reduction based on a perceived failure to remove $1.2 million in capital. While Staff states that the $1.2 million in savings is “on-going in nature” and “should be returned to ratepayers as a known and measurable adjustment,” Staff is removing more than $1.2 million from rates without a coherent explanation as to why this increased adjustment is appropriate.[586]

AWEC proposes to remove the net book value of retired meters from rate base by moving them into a regulatory asset for recovery over 10 years, subject to a lower interest rate, on the basis that the retired assets are no longer used and useful pursuant to ORS 757.355.[587] ORS 757.355 precludes collecting a return on property that is no longer serving customers. PacifiCorp accounts for asset retirements through group depreciation, meaning that Oregon’s distribution assets depreciate collectively.[588] As explained by Hahne in *Accounting for Public Utilities*, the “group concept of depreciation has been an integral part of utility depreciation accounting practice for many years” and under that concept, “no attempt is made to keep track of the depreciation reserve applicable to individual items,” which is a “practical approach for utilities because they possess millions of items of property.”[589] Hahne explains, “each depreciable property group has some ‘average’ life” but the “average is the result of a calculation, and there is no assurance that any of the property items in the group is average.”[590] AWEC’s adjustment fundamentally misunderstands group accounting and is contrary to this long-standing methodology.

AWEC attempts to distinguish the AMI replacement project on the basis that a

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586 Staff’s Prehearing Brief at 57-58.
587 AWEC’s Prehearing Brief at 42.
588 PAC/4400, McCoy/12.
589 Hahne at 6-8.
590 Hahne at 6-8.

substantial share of the Company's meters was replaced.[591] It is not abnormal to upgrade or replace portions of such distribution assets over time, and gradual individual meter replacements would not result in a rate base adjustment.[592] Here, the fact that a larger share of the Company's meters were upgraded within a short time frame should not result in different ratemaking treatment.[593]

XVI. MISCELLANEOUS REVENUE REQUIREMENT

A. __The Commission should approve recovery of PacifiCorp's updated insurance premiums.__

PacifiCorp seeks to recover its reasonable forecast of liability and property insurance premiums for the 2021 Test Year, which include increased insurance costs associated with heightened wildfire risk.[594] Staff objects on the basis that the Company's insurance premiums were updated in reply testimony, and that Staff therefore was "deprive[d]" of the opportunity to review and analyze costs.[595] PacifiCorp's reply testimony was filed on June 25, 2020. Given the discrete and verifiable nature of this cost, Staff had time to request further information about it before its rebuttal testimony, not only by issuing data requests, but during the prearranged bi-weekly calls with parties.[596]

Staff also asks the Commission to adopt Staff's adjustment to the low claims bonus, but simultaneously refers to the Company's testimony demonstrating that this low claims bonus is already reflected in Test Year insurance premiums.[597] Staff is correct that the low claims adjustment is included in the Company's surrebuttal revenue requirement, obviating the basis for

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[591] AWEC's Prehearing Brief at 44 ("This is distinguishable from normal retirement circumstances in which small increments of property are removed and replaced at the end of their useful life.").
[592] PAC/4400, McCoy/12.
[593] PAC/4400, McCoy/12-13.
[594] PAC/3100, McCoy/21.
[595] Staff's Prehearing Brief at 55.
[596] PAC/4400, McCoy/36.
[597] Staff's Prehearing Brief at 56.

Staff's adjustment.[598]

B. <u>The Commission should reject Staff's adjustments to franchise fees and the Oregon Department of Energy supplier fee.</u>

PacifiCorp proposes to base Test Year costs for franchise fees and the Oregon Department of Energy (ODOE) supplier fee percentages based on the three most recently completed calendar years, 2017-2019, rather than the years 2016-2018 proposed by Staff.[599] PacifiCorp updated its Franchise Fees and ODOE fee percentages to adopt Staff's preferred approach, which is based on a three-year-average.[600] Given that 2017-2019 are the three most recent calendar years, the Company's calculation is the most accurate calculation and should be adopted.

C. <u>The Commission should reject Staff's proposed adjustments for dues and memberships expenses.</u>

Staff proposes an adjustment of $34,270 for dues, licenses, memberships and subscriptions.[601] As PacifiCorp witness Ms. McCoy explained, Staff mistakenly based part of its adjustment on system-allocated costs.[602] Moreover, Staff's proposal is inconsistent with Staff's position in recent rate cases, including Cascade Natural Gas Company's 2016 rate case,[603] indicating that such costs are appropriately included at the 75 percent rate proposed in the Company's filing.[604]

D. <u>The Commission should reject Staff's proposed adjustments for meals and entertainment expenses.</u>

Staff proposes an adjustment of $594,533 to the Company's meals and entertainment,

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[598] Staff's Prehearing Brief at 56; PAC/4400, McCoy/35, Table 2.
[599] PAC/4400, McCoy/37.
[600] PAC/4400, McCoy/37.
[601] Staff's Prehearing Brief at 45.
[602] PAC/4400, McCoy/41.
[603] *In the Matter of Cascade Nat. Gas Corp. Request for a Gen. Rate Revision*, Docket UG 305, Staff/600, Zarate/5-6.
[604] PAC/4400, McCoy/41.

awards, miscellaneous, donations, airfare, travel, and lodging. Staff's itemized meals and entertainment adjustments are arbitrary as they are purely based on key words, without considering the actual basis for the expense.[605] Staff further reduces meals and entertainment expenses by 50 percent. Staff claims that its adjustment is consistent with the Commission's Order No. 09-020.[606] Order No. 09-020 rejected PGE's assertion that meals and entertainment expenses were necessary to attract and retain qualified employees. This case is inapplicable because PacifiCorp proactively limits meals and entertainment expenses to those costs clearly associated with a business purpose.[607]

E. **The Commission should reject Staff's adjustments to miscellaneous O&M non-labor expenses.**

Staff proposes a downward adjustment of $2,720,541 to PacifiCorp's Test Year O&M non-labor expense for FERC Accounts 570 (maintenance of station equip), 583 (overhead line expenses), 587 (customer installation expenses), 592 (maintenance of station equipment) and 594 (maintenance of underground lines), on the basis that PacifiCorp provided no justification for the Company's increased costs.[608] This is incorrect. PacifiCorp explained the nature of these cost increases, and provided an exhibit that broke down each adjustment impacting the relevant FERC accounts, while further noting that each adjustment was supported by Ms. McCoy's individual workpapers.[609] PacifiCorp has thoroughly and reasonably documented its expenses and Staff's adjustment should be rejected.

XVII. CONCLUSION

PacifiCorp's rate request accounts for approximately $10 billion in investments since

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[605] PAC/3100, McCoy/25.
[606] Staff's Prehearing Brief at 46-47 (citing *In the Matter of Portland Gen. Elec. Co. Request for a Gen. Rate Revision*, Docket UE 197, Order No. 09-020 at 16 (Jan. 22, 2009)).
[607] PAC/3100, McCoy/24.
[608] Staff's Prehearing Brief at 59.
[609] Staff/3001, Beitzel/1; PAC/4408, McCoy/1.

2013, while delivering an overall rate decrease to customers when offset with the 2021 TAM and TCJA credits. PacifiCorp has presented substantial evidence to show that its investments and costs were prudently incurred and that its proposed rate revision is reasonable and necessary.

The adjustments presented by Staff and intervenors are unsubstantiated or unwarranted. These adjustments reduce PacifiCorp's rates to a level that would undermine its ability to implement changes mandated by Oregon energy policy. The Commission should approve PacifiCorp's proposed revenue requirement and proposed regulatory mechanisms. The Commission should also reject Staff's and intervenors' proposed adjustments as unmerited and deleterious to PacifiCorp's ability to provide safe and reliable service to Oregon customers.

Dated this 28th day of September 2020.

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 374

PACIFICORP

Attachment A to PacifiCorp's Opening Brief

Adjustment Appendix

REDACTED

September 28, 2020

PacifiCorp's Revenue Requirement Changes
(millions)

Revenue Requirement Increase (FILED)	$78.0
Corrections:	
Wages & Benefits	(1.8)
Advertising Expenses	(1.0)
Other Corrections	(0.2)
Updates:	
Increased Vegetation Management	9.0
Use Cholla 4 Excess Deferred Income Tax (EDIT) to offset Cholla balances	1.2
Increase in Insurance Premiums	1.1
Move Deer Creek pension costs from TAM	0.8
Incremental Advanced Metering Infrastructure (AMI) Net Benefits	(6.7)
Updated Escalation Factors	(5.0)
Amortization of Oregon Depreciation Deferral	(2.7)
Decrease Reliability Coordinator Fee	(0.6)
Other updates	(0.4)
Total Change	(6.2)
Reply Revenue Requirement Increase	$71.8
ROE Update to 9.80%	(12.3)
Depreciation Study Settlement	(10.7)
Depreciation Rate Update Impact on Other Adjustments	(0.3)
Depreciation Update Impact on Protected EDIT	0.4
Cholla 4 Decommissioning Regulatory Liability	(0.7)
Remove 2021 Wildfire Capital Projects	(0.7)
Other Updates	(0.1)
Total Change	**(24.4)**
Surrebuttal Revenue Requirement Increase	**$47.5**

Staff's Revenue Requirement Adjustments to PacifiCorp's Surrebuttal Position
(millions)

PacifiCorp Surrebuttal Revenue Requirement Increase	$47.5
Staff's Additional Adjustments	
Capital Structure - 51.86% equity	(5.9)
ROE - 9.00%	(23.9)
Cost of Debt – Increase from 4.77% to 4.82%	1.1
Jim Bridger 3 & 4 SCRs – 10% Gross Plant Disallowance	[redacted]
Transmission Disallowance – Cost Overruns	(0.7)
Transmission Disallowance – Classification	(1.6)
Transmission Disallowance – Pro Forma Additions[1]	(7.8)
Customer Accounts Reduction[2]	(1.5)
Operations & Maintenance Reduction[3]	(2.8)
Administrative & General Reduction[4]	(1.0)
Wages and Salaries	(3.0)
Incentive Compensation	(3.4)
Pension Settlement Costs	(2.3)
Addition of Oregon Corporate Activity Tax (OCAT)	5.7
Meals, Memberships, and Dues	(0.2)
Insurance Premiums	(1.1)
Vegetation Management and Wildfire Mitigation – Costs Moved to Mechanism	(6.9)
AMI Benefits	(2.0)[5]
Incremental Decommissioning Costs	[redacted]
Low Claims Insurance Bonus	(0.2)[6]
Jim Bridger 3 & 4 SCRs – Depreciation Adjustment	[redacted]
Hayden 1 & 2 SCRs – Depreciation Adjustment	
Craig 2 SCR – Depreciation Adjustment	
Hunter Unit 1 Low NOx Burner & Baghouse – Depreciation Adjustment	
Total Change	**(87.6)**
Staff's Revenue Requirement Decrease	**$(40.1)**

[1] This adjustment does not include disallowance of the Sams Valley substation or the 3 Phase Wye-Delta XFMR project, as Staff's Prehearing Brief states that it has no adjustment to either project. Staff's Prehearing Brief at 26-27.
[2] This adjustment reflects Staff's use of All Urban CPI instead of IHS Markit industry-specific escalation factors.
[3] This adjustment reflects Staff's use of All Urban CPI instead of IHS Markit industry-specific escalation factors.
[4] This adjustment reflects Staff's use of All Urban CPI instead of IHS Markit industry-specific escalation factors.
[5] Staff's Prehearing Brief proposes to reduce the Company's opening revenue requirement request for AMI by $8.7 million. PacifiCorp has already included a revenue requirement adjustment of $6.7 million to account for AMI benefits. PAC/3100, McCoy/27. Staff's Prehearing Brief mistakenly refers to the Company having included a revenue requirement adjustment of $6.5 million. Staff's Prehearing Brief at 57. Staff appears to have conflated the Company's expense reduction with the revenue requirement impact. Reductions in expenses do not translate to a dollar-for-dollar reduction in revenue requirement.
[6] This adjustment is based on an error because it is already included in the Company's revenue requirement.

AWEC's Revenue Requirement Adjustments to PacifiCorp's Surrebuttal Position
(millions)

PacifiCorp Surrebuttal Revenue Requirement Increase	$47.5
AWEC's Additional Adjustments	
ROE - 9.20%	(18.5)
Capital Structure – 51.86% equity	(5.4)
Bridger 3 & 4 SCRs – Complete Disallowance	(7.7)
Hunter Unit 1 Low NOx Burner & Baghouse – Complete Disallowance	(2.8)
AMI Replaced Meters[7]	0.4
Cholla Property Tax	[redacted]
Deer Creek – Closure Costs and Royalties[8]	[redacted]
Incremental Decommissioning Costs	[redacted]
Total Change	**(65.3)**
AWEC's Revenue Requirement Decrease	**$(17.8)**

[7] This adjustment removes estimated net book value from rate base for recovery over 10 years at 1.66% carrying charge.
[8] This adjustment limits mine closure costs to original estimate and continues to defer royalties until paid.

Sierra Club's Revenue Requirement Adjustments
to PacifiCorp's Surrebuttal Position
(millions)

PacifiCorp Surrebuttal Revenue Requirement Increase	$47.5
Sierra Club's Additional Adjustments	
ROE – 9.20%	(18.5)
Capital Structure – 51.86% equity	(5.4)
Bridger 3 & 4 SCRs – Complete Disallowance	(7.7)
Hayden 1 & 2 SCRs – Complete Disallowance	(0.8)
Total Change	**(32.4)**
Sierra Club's Revenue Requirement Increase	**$15.1**

CUB's Revenue Requirement Adjustments
to PacifiCorp's Surrebuttal Position
(millions)

PacifiCorp Surrebuttal Revenue Requirement Increase	$47.5
CUB's Additional Adjustments	
ROE – 9.40%	(12.3)
Bridger 3 & 4 SCRs – Complete Disallowance	(7.9)
Incremental Decommissioning Costs	[redacted]
Total Change	[redacted]
CUB's Revenue Requirement Increase	[redacted]