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June 22, 2022

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
Docket Nos. UE 399, UM 1694, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201

Dear Filing Center:

Please find enclosed the redacted Opening Testimony and Exhibits of Bradley G. Mullins (AWEC/100 – 105) and Lance D. Kaufman (AWEC/200 – 203) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's testimony and exhibits contain Protected Information that is being handled in accordance with General Protective Order No. 22-044. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Corinne O. Milinovich
Corinne O. Milinovich

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Alliance of Western Energy Consumers' Redacted Opening Testimony and Exhibits** upon the parties shown below by sharing encrypted copies via electronic mail.

Dated this 22nd day of June, 2022

Sincerely,

<u>/s/ Corinne O. Milinovich</u>
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision
(UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120
(UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

OPENING TESTIMONY OF

BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

June 22, 2022

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AWEC/105 - Fly Ash Deferral Calculation

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a consultant for MW Analytics, an independent consulting firm representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found in Exhibit AWEC/101.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's proposed $84,399,290 base rate revenue requirement increase, which if approved, would result in a 6.8% rate increase. As discussed below, AWEC's initial review supports a revenue requirement sufficiency of $2,961,708. The specific adjustments leading to this recommendation are detailed in Exhibit AWEC/102 and discussed below.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I reviewed PacifiCorp's filed testimony, workpapers and revenue requirement models. I submitted multiple rounds of data requests and reviewed PacifiCorp's responses to those requests. I also reviewed PacifiCorp's response to data requests submitted by Staff, CUB and other parties. Copies of relevant data requests from this proceeding may be found in Exhibit AWEC/103.

Q. PLEASE SUMMARIZE YOUR PRINCIPAL RECOMMENDATIONS AND CONCLUSIONS.

A. In conjunction with the ongoing transition adjustment mechanism ("TAM"), ratepayers are facing rate increases of approximately 12.4%. This does not include the 4.0% overall increase customers are facing in PacifiCorp's Power Cost Adjustment Mechanism ("PCAM") filing, Docket No. UE 404, or the additional costs customers may face associated with incremental decommissioning and remediation expense at PacifiCorp's coal plants in UM 2183. AWEC's initial revenue requirement recommendations are summarized in Table 1, below.

Table 1
AWEC Initial Revenue Requirement Recommendation, Oregon-Allocated ($000)

1	**Initial Proposal (GRC)**		**84,399**
	Impact of Adjustments		
2	A1	Cost of Capital (Gorman)	(20,160)
3	A2	Tax Benefit of BHE Interest	(10,222)
4	A3	State NOL Carryforwards	(1,712)
5	A4	Inj. & Damages DTA	(287)
6	A5	Environmental Reg. Assets	(2,490)
7	A6	Insurance Expense	(3,227)
8	A7	Trapper Mine - Reclamation	(186)
9	A8	Trapper Mine - Prudence	(96)
10	A9	Fuel Stock - Forecast	(338)
11	A10	Fuel Stock - Rock Garden	(741)
12	A11	Meter Replacement Amortization	(1,000)
13	A12	Prepayments	(3,766)
14	A14	Old Mobile Radio	(383)
15	A15	Wind Projects Deferral	(6,349)
16	A16	Fly Ash Deferral	(1,963)
17	A17	Utah Schedule 34	(7,360)
18	A18	Utah DSM	(9,097)
19	A19	Coal Depr. Lives (Kaufman)	(15,715)
20	A20	Rolling Hills (Kaufman)	(2,171)
21	A21	Wildfire Disallowance (Kaufman)	(1,447)
22	A20	Interest Coordination	1,350
23	**Total Adjustments**		**(87,361)**
24	**Adjusted Revenue Requirement**		**(2,962)**

The summary above also incorporates the recommendations of witnesses Gorman and Kaufman, who are also filing testimony on behalf of AWEC in this proceeding.

II. REVENUE REQUIREMENT ISSUES

a. Tax Benefit of Holding Company Interest

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE TAX BENEFIT OF BERKSHIRE HATHAWAY ENERGY INTEREST EXPENSE?

A. In ORS 757.269(3), the Commission is directed to consider the impacts of an affiliated group on the tax expenses that are included in the general rates of an electric utility. The statute states "for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon: (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation; (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or (c) Any other considerations the commission deems relevant to protect the public interest."[1] PacifiCorp files its taxes as a part of an affiliated group. Therefore, I recommend the Commission apply the standard outlined in ORS 757.269(3) when evaluating the income taxes to be included in revenue requirement in this proceeding.

Q. HOW DOES PACIFICORP'S CORPORATE STRUCTURE IMPACT THE TAXES IT PAYS?

A. PacifiCorp is a wholly owned subsidiary of Berkshire Hathaway Energy ("BHE"), which itself is a wholly owned subsidiary of Berkshire Hathaway. Accordingly, PacifiCorp files consolidated income tax returns with Berkshire Hathaway as a part of a large, affiliated group.[2] While many of the tax deductions and benefits of being a part of the affiliated group flow

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[1] ORS 757.269(3).
[2] ORS 757.269(5) defines an "affiliated group" as "a group of corporations of which the public utility is a member and that files a consolidated federal income tax return."

directly to the individual companies that make up the affiliated group, the holding company independently borrows and deducts interest on its debt in a manner that offsets the taxes paid by the individual companies in the affiliated group. This is an operating strategy that companies may employ to reduce their tax liability. Rather than borrowing at the individual company level, the borrowing occurs at the parent level which increases leverage and reduces the overall taxes paid by the affiliate group.

Q. HOW MUCH DEBT DOES BHE HOLD?

A. In recent years, BHE has been increasingly borrowing at historically low interest rates, while PacifiCorp's rates of dividends have slowed. As of December 31, 2021, BHE had issued over $13,003,000,000 in outstanding debt securities.[3] Thus, rather than PacifiCorp issuing debt, BHE, which holds no independent operating assets, is basically borrowing against future dividends and receiving both the tax and leverage benefits associated with the borrowing, without passing those benefits on to ratepayers. Thus, the affiliated group is able to reduce its overall tax liability for interest expenses incurred at the holding company level, the benefit of which is not reflected in the revenue requirement that PacifiCorp has proposed in its initial filing. This corporate structure results in the affiliated group paying federal and state income taxes that are less than the amounts that would be paid if PacifiCorp were an Oregon-only regulated utility. Accordingly, consistent with ORS 757.269(3), it is in the public interest for the Commission to consider the tax benefits of interest held by BHE in the calculation of PacifiCorp's taxable income in revenue requirement.

[3] Berkshire Hathaway Energy Company, Form 10-K Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2021, at 154.

Q. WHAT IS THE AMOUNT OF INTEREST EXPENSE DEDUCTED BY BHE?

A. The level of debt held, and interest expense paid by, BHE has been increasing based on its consolidated 10-K filings. In 2021, Berkshire Hathaway Energy incurred $580,000,000 in interest at the holding company level.[4] The approximate debt and interest expense incurred by BHE at the holding company level, along with the amounts attributed to PacifiCorp, are summarized in Exhibit AWEC/104 based on BHE's 2021 10-K filing. As can be seen, BHE had $13,003,000,000 in long term debt on its books as of December 31, 2021. With an average interest rate of 4.28%, this debt corresponds to $556,802,000 in interest expenses that are deductible at the holding company level.

PacifiCorp is the largest utility held by BHE and therefore it is impacted more by BHE's borrowing activity than any other subsidiary. As can be seen from the exhibit, as a percentage of total capitalization (net book value), PacifiCorp comprised 20.0% of BHE's balance sheet. Thus, approximately $2,604,834,000 in holding company debt may be attributable to PacifiCorp, representing approximately $111,542,000 of deductible interest expenses. Allocated to Oregon using the System Overhead ("SO") factor, this debt represents $30,309,300 in interest deduction attributable to Oregon utility operations, the tax benefit of which is $7,456,088 at a 24.6% effective tax rate.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF CONSIDERING THE TAX BEFIT OF THIS INTEREST?

A. Grossed-up to revenue requirement, the tax benefit calculated in AWEC/105 results in a $10,222,032 reduction to the Oregon revenue requirement. Thus, BHE's decision to increasingly borrow at the holding company level, rather than receiving dividends from its

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[4] *Id.* at 467.

subsidiaries, has resulted in material tax benefits to the affiliated group. It would be contrary to the public interest to withhold the benefits of this strategy from ratepayers when setting rates.

b. <u>State Net Operating Loss Carryforwards</u>

Q. WHAT LEVEL OF STATE NET OPERATING LOSS CARRYFORWARDS DOES PACIFICORP INCLUDE IN REVENUE REQUIREMENT?

A. As can be noted in the B-Tab workpaper of PacifiCorp Witness Cheung titled "B19 - Deferred Income Tax Balance," PacifiCorp's filing includes a line item for "DTA Net Operating Loss Carryforward-State" resulting in a deferred tax asset in the amount of $66,982,587, with $18,201,961 allocated Oregon.

Q. WHAT DO YOU RECOMMEND FOR THE STATE NET OPERATING LOSS ("NOL") AMOUNTS?

A. I recommend that the NOL balances be eliminated from revenue requirement, since they do not represent a benefit to Oregon customers. The fact that PacifiCorp has such a high NOL balance, indicates that it is not, and has not been paying state taxes for a significant amount of time. PacifiCorp provided its history of NOLs by state in response to AWEC Data Request 34. Based on that response, the NOL balances have been persistent since at least 2017.

Q. IS IT REASONABLE FOR PACIFICORP TO RECOVER THE COST OF STATE TAXES IF IT IS NOT PAYING ANY STATE TAXES?

A. No. If ratepayers are to pay a financing charge on the state NOLs it would be appropriate for the benefit of the NOL also to be passed on to ratepayers through the elimination of state taxes. It is not reasonable to require customers to pay a cost for state NOL carryforwards, while also continuing to pay for the state taxes that PacifiCorp is avoiding as a result of the NOL carryforwards. Based on my review of their filings, other utilities with large state carryforward balances, such as Avista, have eliminated state taxes from revenue requirement.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This recommendation produces an $18,201,961 reduction to rate base and a corresponding $1,721,588 reduction to revenue requirement.

c. <u>Injuries and Damages Deferred Tax Asset</u>

Q. WHAT DEFERRED TAX ASSET DOES PACIFICORP INCLUDE IN REVENUE REQUIREMENT FOR INJURIES AND DAMAGES?

A. In response to AWEC Data Request 30, PacifiCorp identifies a deferred tax asset in the amount of $3,053,000 Oregon-allocated that is associated with a contingent liability it has booked as injuries and damages. This amount may be found in the workpaper of witness Cheung "B19 - Deferred Income Tax Balance" under the line item "DTA 705.400 Reg Lia - OR Inj & Dam Reser." In its response, PacifiCorp states that this tax asset is related to its "monthly accruals and related reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution property losses, and third-party liability insurance."

Q. IS THIS TAX ASSET APPROPRIATE TO INCLUDE IN REVENUE REQUIREMENT?

A. No. The tax asset that PacifiCorp claims as related to the Oregon method for calculating self-insurance costs is better assigned to non-utility operations. The method that is used to calculate injuries and damages expenses, based on a three-year average, does not have the effect of introducing tax liability in revenue requirement nor does it have the effect of a deferral. Rather the approach is simply a method for normalizing the expense, which does not necessitate the need for a deferred tax asset. If anything, because the method for calculating injuries and damages is based on historical expenses, that would result in a deferred tax liability, since the amounts deducted in the historical period are not recovered until later, at which point the tax liability would arise.

Q. WHAT IS THE IMPACT OF REMOVING THIS DEFERRED TAX ASSET?

A. Eliminating the $3,053,000 in Oregon rate base results in a $287,212 reduction to revenue requirement.

d. <u>Environmental Regulatory Assets</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO PACIFICORP'S ENVIRONMENTAL REGULATORY ASSETS?

A. In Cheung workpaper "B16 - Regulatory Assets", Account "1823910 - ENVIR CST UNDR AMORT", PacifiCorp identified 48 regulatory assets with a total balance of $9,402,000 allocated to Oregon. In response to AWEC Data Request 02, Attachment AWEC 02, PacifiCorp also identified $1,552,529 in Oregon-allocated amortization expense associated with these regulatory assets. These amounts represent environmental expenditures that have not been demonstrated to be prudent, such as the cost of remediating oil and ash spills at coal plants, and which the Commission never approved for regulatory accounting. Accordingly, I recommend that these unapproved regulatory assets, and the associated amortization, be removed from the revenue requirement.

Q. WHAT ARE THE SPECIFIC EXPENDITURES THAT WERE INCLUDED IN THE REGULATORY ASSETS?

A. In AWEC Data Request 02, PacifiCorp was requested to provide a description of each of the regulatory assets included in Account 1823910. In Attachment AWEC 02, provided in response, PacifiCorp provides a list of expenditures, many of which raise questions regarding prudence. For example, the list included items such as oil leaks at the Wyodak power plant, contaminated groundwater from a gasoline leak, remediation costs at Klamath Falls, and a leak of creosote into groundwater at an Idaho pole yard. These types of costs appear, on their face, to be imprudent expenditures, and in any event, PacifiCorp has not demonstrated that they are in fact prudent. Therefore, including them in a regulatory asset without specific Commission authorization is not appropriate.

Q. HAS PACIFICORP REQUESTED A REGULATORY ACCOUNTING ORDER TO JUSTIFY THESE REGULATORY ASSETS?

A. No. In response AWEC Data Request 2, PacifiCorp was requested to identify the accounting order that approved the regulatory assets but was unable to do so. Instead, PacifiCorp stated "Environment Costs Regulatory Assets were approved as part of the settlement outcome in Oregon's general rate case (GRC), Docket UE 147." PacifiCorp also stated that "since the 2003 GRC, this approved treatment of environmental costs being deferred and amortized over ten years has been continuously applied and approved in all subsequent GRCs."

Q. WERE THESE ENVIRONMENTAL REMEDIATION REGULATORY ASSETS ADDRESSED IN THE STIPULATION IN DOCKET NO. UE 147?

A. No. There was no reference to these environmental remediation regulatory assets in the Stipulation in Docket No. UE 147. Therefore, PacifiCorp's statement that the assets were approved in that docket is not true. Further, most, if not all, of the expenditures included in the regulatory account were incurred subsequent to 2003. Thus, any agreement in 2003 would be largely irrelevant to the regulatory assets that PacifiCorp has included in this case.

Q. IS IT RELEVANT THAT PACIFICORP HAS INCLUDED SIMILAR ENVIRONMENTAL REGULATORY ASSETS IN PAST PROCEEDINGS?

A. No. To book a regulatory asset, PacifiCorp must have a specific accounting order from the Commission. PacifiCorp cannot include a regulatory account in rates without specifically requesting it be included. While similar environmental regulatory assets might have been included in rates in past proceedings, the Commission has never explicitly approved these specific regulatory assets. Asserting that an accounting order was somehow implied by those past orders is not sound regulatory accounting. Therefore, including the environmental regulatory assets in this case is not appropriate, irrespective of what has been done in the past.

Q. WHAT CRITERIA DOES PACIFICORP USE TO DETERMINE WHETHER TO INCLUDE A COST IN THE ENVIRONMENTAL COST REGULATORY ASSET?

A. The asset includes a wide range of costs items, ranging from oil spills to ash landfill reclamation, so it is not necessarily clear what criteria or method PacifiCorp is using to determine whether a cost is eligible for regulatory asset treatment or would otherwise be recoverable through general rates. Having a specific accounting order from the Commission is necessary to know whether a particular cost is eligible to be included in the regulatory asset, and absent such an order, the method employed for determining what costs to include has the potential to be arbitrary.

Q. ARE THESE COSTS RECURRING?

A. No. Rates are set based on the assumption that PacifiCorp will operate its system prudently in the test period, avoiding the types of oil spills and other environmental failures that it has been including the environmental remediation regulatory assets. Therefore, including this type of environmental expense in this general rate case is not appropriate because the costs are non-recurring in nature.

Q. WHAT IS THE IMPACT OF REMOVING THESE REGULATORY ACCOUNTS AND THE ASSOCIATED AMORTIZATION?

A. The impact is a $9,402,000 reduction to Oregon-allocated rate base and a $1,552,529 reduction to amortization expense. These adjustments produce a revenue requirement reduction of $2,489,636.

e. <u>California Wildfire Premiums</u>

Q. PLEASE DESCRIBE THE ADJUSTMENT THAT PACIFICORP MAKES FOR INSURANCE EXPENSES.

A. In Cheung workpaper “4.5 - Insurance Expense” PacifiCorp makes a pro forma adjustment to insurance expense. This adjustment results in a $20,792,083 increase to liability insurance on a total-company basis, with $5,649,850 of the increase allocated to Oregon.

Q. WHAT IS DRIVING THE INCREASE?

A. In testimony, PacifiCorp states that the “increase in renewed liability insurance premiums effective August 15, 2021, is attributable to wildfire risk and other factors outside PacifiCorp’s control.”[5] In response to AWEC Data Request 16, Confidential Attachment AWEC 16, PacifiCorp provided detail showing that California wildfire premiums were a source of the increase in liability insurance.

Q. WHY IS THERE A SEPARATE POLICY FOR CALIFORNIA LIABILITY INSURANCE?

A. California has adopted a policy known as inverse condemnation. Under that policy, utilities are strictly liable for any damages caused by their activity or equipment, regardless of fault or foreseeability. Since that risk is unique from the wildfire risk in other states, the California wildfire insurance is a separate policy with a different premium level reflecting the risks associated with inverse condemnation.

Q DO OREGON RATEPAYERS BENEFIT FROM CALIFORNIA’S INVERSE CONDEMNATION POLICY?

A. No. Oregon customers do not have similar legal rights as those of California customers for recovering damages associated with wildfires. Therefore, requiring Oregon customers to pay

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[5] PAC/1000, Chueng/21:11-12.

the cost of California's inverse condemnation policy, when they do not benefit from that policy, is not reasonable.

Q. WHAT DOES THE 2020 PROTOCOL SAY ABOUT STATE SPECIFIC POLICIES?

A. In the 2020 Protocol, state specific policies are generally allocated to the state implementing such policy. Section 5.8 of the 2020 Protocol states that "[c]osts and benefits resulting from a State-specific initiative will continue to be allocated and assigned on a situs basis to the State adopting the initiative." Thus, under the terms of the 2020 Protocol, the liability insurance premiums associated with California's inverse condemnation policies are most appropriately allocated to California customers.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. Removing the California wildfire insurance premiums from Oregon revenue requirement reduces Oregon-allocated revenue requirement by $3,226,915.

f. <u>Trapper Coal Mine Reclamation</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE TRAPPER MINE DECOMMISSIONING FUND.

A. In Cheung workpaper "8.2 - Trapper Mine Rate Base," Tab "8.2.2" it can be noted that on June 21, 2021, PacifiCorp had accrued $7,672,867 in a liability account to fund reclamation at the Trapper Coal Mine, a captive mine serving the Craig coal fired power plant in western Colorado. PacifiCorp is a co-owner of the Craig power plant and a 29.14% owner of the Trapper Coal Mine. PacifiCorp's experience with the closure of the Deer Creek Coal Mine, the cost of which customers are still paying today, demonstrates the importance for PacifiCorp to prudently manage the operation and decommissioning liability at its captive coal mines. In the case of the Trapper Coal Mine, PacifiCorp's expected decommissioning liability was provided in Docket No. UE 400 in response to AWEC Data Request 56, Confidential

Attachment 56.[6] To fund this liability, PacifiCorp accrues a monthly reclamation expense, which is included in the cost of coal for the Craig power plant in the TAM.

Q. ARE THE RECLAMATION FUNDS HELD IN A TRUST?

A. No. The funding for the reclamation liability is not necessarily transparent because there is little accountability for the large amount of funds that are being set aside by the joint owners of the Trapper Mine to fund remediation. The mine's financial statements were provided in response to AWEC Data Request 23, Confidential Attachment AWEC 23. The mine itself currently holds a significant amount of cash, likely as a result of the reclamation liability that it is holding on behalf of owners, while much of the reclamation liability is held as a receivable from owners, who have yet to fund their obligations. Thus, it's not clear how the mine is using the funds dedicated for reclamation, whether it is drawing on the funds, or if there are any other restrictions that have been put in place to prevent improper usage of the funds. Based on its response to AWEC Data Request 19, for example, it appears that PacifiCorp holds the reclamation funds on its own books rather than contributing the funds to the Trapper coal mine, although there appear to be no restrictions on the internal use of those funds by PacifiCorp through the establishment of a reclamation trust, for example. Rather, the reclamation funds are held in a cash working capital liability account on PacifiCorp's books and are available to fund its ongoing operations.

Q. WHAT PRO FORMA ADJUSTMENT DOES PACIFICORP MAKE WITH RESPECT TO THE RECLAMATION LIABILITY?

A. Due to ongoing contributions to the reclamation liability, the liability balance is expected to increase in the pro forma period. PacifiCorp, therefore, makes an adjustment, relative to the

[6] PacifiCorp provided AWEC with permission to use this Data Response from Docket No. UE 400 in this docket.

amount accrued in the cash working capital account in the test period, to the average balance in the pro forma period. The reclamation liability included in cash working capital was $7,150,412, versus the 12-month average in the pro forma period of $9,303,790, yielding a total-company $2,153,378 reduction to rate base.

Q. DO YOU AGREE WITH PACIFICORP'S CALCULATION?

A. No. There are two problems with PacifiCorp's calculations.

First, PacifiCorp uses the average balance, instead of the end-of-period balance when calculating the reclamation liability in its adjustment. End-of-period balances are used for all other aspects of rate base, and it is appropriate to use an end of period balance for purposes of the reclamation liability, which is increasing rapidly due to ongoing contributions. While the average reclamation liability balance was $9,303,790 in the pro forma period, the end-of-period, December 31, 2022 balance was forecast to be $10,050,024, which is a more appropriate value to include in revenue requirement.

Second, PacifiCorp assumes that $7,150,412 of test period reclamation liability is already reflected in revenue requirement because the amount was included in a cash working capital account. That, however, is not accurate. The cash working capital accounts are not included in the test period revenue requirement because PacifiCorp's working capital is established using its 2015 lead-lag study. The specific cash working capital account identified in response to AWEC Data Request 19, where the reclamation liability is being held, is not included in rate base, nor is the reclamation liability considered in the lead-lag study. Accordingly, deducting the $7,150,412 in liability included in cash working capital was an error.

Q. WHAT IS THE IMPACT OF THESE CHANGES?

A. Adjusting to the end-of-period balances and eliminating the deduction for the test period balance included in cash working capital results in a $7,896,645 reduction to total-company rate base, with $1,979,541 allocated to Oregon. These reductions result in a $186,226 reduction to revenue requirement.

g. <u>Trapper Mine Prudence</u>

Q. WHAT AMOUNT OF RATE BASE DOES PACIFICORP INCLUDE FOR THE TRAPPER MINE IN THE TEST PERIOD?

A. As can be seen in Cheung workpaper "8.2 - Trapper Mine Rate Base", PacifiCorp includes $8,157,216 in total-company rate base associated with the Trapper Mine, with $2,044,862 allocated to Oregon.

Q. WHAT SUPPORT DID PACIFICORP PROVIDE FOR THE PRUDENT OPERATION OF THE TRAPPER COAL MINE?

A. PacifiCorp has been unable to provide any evidence demonstrating that it is prudently managing the operations at the Trapper Coal Mine. For example, in AWEC Data Request 56, PacifiCorp was requested to identify each pit at the Trapper Coal Mine and the date that mining began at each pit. PacifiCorp responded, "Trapper Mine does not maintain a report with this information."

Q. WHAT DO YOU RECOMMEND?

A. Given PacifiCorp's inability to provide concrete information demonstrating that the mine is being prudently managed, I recommend a disallowance equal to 50% of the rate base, and corresponding depreciation expenses, at the Trapper Mine. The decisions that are being made at the Trapper Mine are not inconsequential and deserve to be monitored and evaluated by PacifiCorp in a thorough and thoughtful manner. The timing and decision to open a new pit at the mine, for example, could result in large sums of stranded costs being borne by ratepayers. The fact that PacifiCorp has no information regarding the individual pits that are even in operation at the mine nor the date that they began operation is concerning, to say the least. The impact of this recommendation is a $96,185 reduction to revenue requirement.

h. <u>Fuel Stock Forecast</u>

Q. WHAT IS FUEL STOCK?

A. Fuel stock is the financial balance for the coal pile held on site at individual coal fired power plants. PacifiCorp must invest in a coal pile at each of the facilities to ensure their reliable operation. Accordingly, the balance of fuel stock is typically included in rate base, upon which PacifiCorp earns its rate of return. The rate base balances for fuel stock were provided in Cheung workpaper "8.15 – Miscellaneous Rate Base." In this case PacifiCorp is requesting a fuel stock balance of $174,547,782 based on a forecast of 13-month average balances over the year ending December 2022.

Q. DID YOU REQUEST PACIFICORP PROVIDE WORKPAPERS SUPPORTING ITS FUEL STOCK FORECAST?

A. Yes. In AWEC Data Request 52, PacifiCorp was requested to provide all workpapers supporting its calculation of fuel stock. In response, PacifiCorp provided Confidential Attachment AWEC 52, which included only hardcoded monthly values associated with the fuel stock balances, rather than the workpaper used to calculate the balances. PacifiCorp's inputs were based on the average fuel stock balances forecast over the 12-months ending December 2023. In that attachment, it is apparent, however, that PacifiCorp's forecast includes some major increases to the fuel stock levels expected at certain plants over the proforma period, although those increases are not explained. In total the forecast was for fuel stock to increase by 16.4%. The Hunter plant, for example, had a forecasted 40.5% increase in fuel stock, even though the plant is expected to operate at a high capacity factor in the test period.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the increase in fuel stock over the test period be removed from the revenue requirement. PacifiCorp did not provide workpapers to support the increase. Further, the normalized revenue forecast in this proceeding most appropriately reflects an assumption that fuel stock is managed to a constant level over the test period, without any net increase or decrease over the test period. Finally, using the average value over the course of the test period is inconsistent with the rate base valuation that relied on end of period balances calculated as of December 31, 2022. Accordingly, I recommend the December 31, 2022 fuel stock balances be used and that the assumed increase in fuel stock over the test period be eliminated. This recommendation produces a $14,338,002 reduction to total-company rate base with $3,594,270 allocated to Oregon. This rate base adjustment reduces revenue requirement by $338,132.

i. <u>Rock Garden Fuel Stock</u>

Q. WHAT IS THE FUEL STOCK ASSOCIATED WITH ROCK GARDEN?

A. In Cheung workpaper "8.15 - Miscellaneous Rate Base" it can be observed that PacifiCorp includes fuel stock of $31,430,017 on a line-item titled Rock Garden. In response to AWEC Data Request 53, PacifiCorp explained that the Rock Garden coal pile is associated with the Hunter and Huntington power plants and represents a "safety" pile to mitigate risks associated with underground mining.

Q. IS A SAFETY COAL STOCKPILE NECESSARY FOR HUNTER AND HUNTINGTON?

A. No. While PacifiCorp asserts that a "significant number of Utah Coal Companies have filed for bankruptcy," it currently has a long-term agreement with Bowie Resources to serve the

Hunter and Huntington power plants. PacifiCorp entered into the agreement with Bowie when it closed the Deer Creek mine and conducted due diligence regarding Bowie's ability to serve the Hunter and Huntington power plants over the term of the agreement.

Further, the coal piles at the Hunter and Huntington power plants are already high relative to the production from those facilities. It can be noted from Cheung workpaper "8.15 Miscellaneous Rate Base" Tab "8.15.1" that notwithstanding their relative size, Hunter and Huntington have some of the highest fuel stock balances of the entire fleet.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Rock Garden coal pile be considered as plant held for future use and not currently used and useful. This treatment results in a $31,430,017 reduction to total-company rate base, with $7,878,919 allocated to Oregon. The impact of removing these balances is a $741,212 reduction to revenue requirement.

j. <u>Meter Replacement Amortization</u>

Q. WHAT ERROR DID PACIFICORP IDENTIFY WITH RESPECT TO METER REPLACEMENT AMORTIZATION?

A. In response to AWEC Data Request 45, PacifiCorp identified $967,000 of Oregon-allocated amortization expense associated with meter replacements that was booked to a line item titled "Amortz Reg A-Unrcvrd Plt/Decom Csts-OR." PacifiCorp identified this amortization expense as an error. Correcting this error results in a $999,769 reduction to revenue requirement.

k. <u>Prepayments</u>

Q. IS PACIFICORP REQUESTING A WORKING CAPITAL ALLOWANCE?

A. Yes. PacifiCorp is requesting a working capital allowance of $29,774,416. This amount was calculated based on the results of its 2015 lead lag study.

Q. HAS PACIFICORP INCLUDED OTHER WORKING CAPITAL BALANCES IN ADDITION TO ITS PROPOSED WORKING CAPITAL ALLOWANCE?

A. Yes. In Cheung workpaper "B15 - Miscellaneous Rate Base," PacifiCorp includes a variety of prepaid expenses related to items such as prepaid insurance, prepaid taxes and other prepaid funds. Further, in Cheung workpaper "B11 - Deferred Debits," PacifiCorp includes a number of maintenance prepayments, which PacifiCorp pro-forms in workpaper "8.15 -Miscellaneous Rate Base." The total amounts of these prepayments are identified in Table 3 below.

Table 3
Prepayments Included in Revenue Requirement
($000)

Account	Desc.	Total-Co. Amount	Oregon Allocated
1651000	PREPAY-INSURANCE	2,188	595
1652000	PREPAY-TAXES	179	49
1652100	PREPAY - OTHER	65,187	10,487
1868000	MISC DF DR-OTH-CST	110,978	28,904
	Total	178,533	40,034

Q. HOW DO YOU RECOMMEND THE COMMISSION HANDLE THESE OTHER WORKING CAPITAL ACCOUNTS?

A. The lead lag study that PacifiCorp uses to calculate its working capital allowance already provides it with recovery of the financing costs associated with working capital. Therefore, including these additional prepayments is not necessary. Prepaid expenses are also appropriately removed as a normalizing adjustment, as the revenue requirement does not necessarily correspond to the timing of when the amounts are expensed versus paid. Prepaid maintenance expenses, for example, are normalized over a number of years and there is no explicit assumption about the timing of when the expense is paid versus accrued.

Q. WHAT IS THE IMPACT OF REMOVING THESE ITEMS?

A. Removing these items results in a $178,532,842 reduction to total-company rate base with $40,034,106 allocated to Oregon. The impact of this adjustment is a $3,766,220 reduction to revenue requirement.

l. <u>Old Mobile Radio</u>

Q. WHAT IS THE OLD MOBILE RADIO PROJECT?

A. In response to AWEC Data Request 47, PacifiCorp describes $4,071,000 in Oregon-allocated rate base associated with the Old Mobile Radio Project. This plant balance may be found in the workpaper of witness Cheung "B8 – EPIS" under the line item titled "OR VHF (VPC) SPECTRUM." Under the project, as PacifiCorp describes it, "the Company purchased exclusive rights to several channel frequencies for the Company's microwave operations." These rights are perpetual in nature and not being amortized.

Q. DOES THE OLD MOBILE RADIO PROJECT BENEFIT RATEPAYERS?

A. In PacifiCorp's response it did not identify whether the project benefits ratepayers, nor indicate that the spectrum is used and useful for Oregon customers. In addition, PacifiCorp has included the spectrum rights as a perpetual addition with no associated amortization. It is not clear from the response when the rights were acquired, and requiring customers to provide a perpetual return on plant is not reasonable.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Old Mobile Radio project be removed from rate base. The effect of this recommendation is a $382,980 reduction to revenue requirement.

m. Wind Projects Deferral

Q. WHAT DEFERRAL DOES PACIFICORP INCLUDE FOR THE CEDAR SPRINGS AND TB FLATS WIND FACILITIES?

A. In Cheung workpaper "8.14 - Wind Projects Deferrals Amortization" PacifiCorp includes $6,140,445 of Oregon allocated amortization expenses for the Cedar Springs II and TB Flats wind facilities. In the workpaper, PacifiCorp states that it has a pending deferral application in Docket No. UM 2134, where it is seeking to defer the revenue requirement associated with Cedar Springs II, which went into service one month prior to the rate effective date in its 2021 Oregon general rate case. Further, PacifiCorp states that it also has a pending deferral application in Docket No. UM 2186, where it is seeking to defer the revenue requirement impact of plant in service associated with TB Flats II that went into service in July 2021.

Q. DO YOU SUPPORT THESE REQUESTS?

A. No. Both of these requests are problematic from a regulatory perspective. First, the fact that PacifiCorp was subject to a minor amount of regulatory lag with respect to Cedar Springs II in December 2020 is not a valid reason to defer those costs. Further, I recommend that ratepayers be held harmless in connection with the severe delay in the in-service date in TB Flats. Foremost, the fact that the project was delayed ignores other factors that would have offset the cost associated with the delay. For example, the accumulated depreciation and accumulated deferred income tax balances associated with PacifiCorp's other EV 2020 wind facilities are declining quickly. If the benefit of the additional accumulated depreciation and deferred taxes associated with the other wind facilities were considered relative to the amounts included in rates, it would have substantially offset the cost of the deferral. Further, PacifiCorp had the opportunity to file a rate case in 2021 to incorporate the costs of the TB Flats wind project but did not do so.

Q. WHAT IS THE IMPACT OF REMOVING THE WIND PROJECTS DEFERRAL?

A. Removing the wind projects deferral produces a $6,348,530 reduction to revenue requirement.

n. <u>UM 2201 Fly Ash Deferral</u>

Q. PLEASE SUMMARIZE YOU RECOMMENDATION RELATED TO THE FLY ASH DEFERRAL IN DOCKET NO. UM 2201.

A. I recommend the Commission approve the fly ash deferral created by Docket No. UM 2201 and commence amortization over a two-year period consistent with the amortization schedule provided in AWEC/105.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE FLY ASH DEFERRAL.

A. In PacifiCorp's 2021 General Rate Case it included Oregon-allocated fly ash revenues of $1,107,523.[7] Prior to the resolution of the case, however, PacifiCorp executed a new agreement to sell fly ash from the Jim Bridger power plant that was expected to increase fly ash revenues to $4,173,799.[8] In Docket No. UE 390, AWEC identified this increase to fly ash revenues and requested that the increase be considered in the other revenue forecast included in the 2022 TAM.

Q. WHAT DID THE COMMISSION DECIDE?

A. The Commission did not approve AWEC's recommendation but stated "we recommend that Staff seek to use a deferral mechanism, rather than an adjustment to TAM rates, which we would review under our normal approach to deferrals."[9]

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7 Docket No. UM 2201, AWEC Application at 3 (Nov. 2, 2021) (internal citations omitted).
8 *Id.*
9 Docket No. UE 390, Order No. 21-379, at 36 (Nov. 1, 2021).

Q. WHY IS IT REASONABLE TO CONSIDER THE INCREMENTAL FLY ASH REVENUES IN THIS DOCKET?

A. PacifiCorp benefitted from the increased fly ash revenues associated with the new contract, but those amounts were not considered in rates for the benefit of ratepayers. Further, the new contract with Bridger Coal Company was executed and went into effect prior to the date that rates went into effect in the last GRC. Accordingly, it does not implicate single issue ratemaking concerns to consider this deferral since the benefit corresponded to the timing of final rates that were set in Docket No. UE 374. To properly match revenues with expense, it is appropriate to consider the deferred amounts in revenue requirement in this proceeding.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. Based on the amortization schedule in AWEC/105, this recommendation produces a $1,963,490 reduction to Oregon-allocated revenue requirement.

o. Utah Schedule 34

Q. PLEASE PROVIDE AN OVERVIEW OF THE ISSUE YOU RAISED IN DOCKET NO. UE 400 RELATED TO UTAH SCHEDULE 34?

A. In PacifiCorp's concurrent TAM filing, Docket No. UE 400, I recommended an adjustment to PacifiCorp's interjurisdictional allocation factors related to the treatment of a Utah Schedule 34 customer's load. As I noted in Docket No. UE 400, the Utah Schedule 34 customer's load and energy is being removed from Utah's allocation factors. This treatment, however, is inconsistent with the 2020 Protocol, which does not allow states to remove special contract customer loads from their allocation factors.

Q. WHAT IS THE IMPACT OF THAT RECOMMENDATION IN THIS DOCKET?

A. While PacifiCorp did not provide the specific load associated with the Utah Schedule 34 customer, I performed an estimate of the impact on allocation factors in my Opening

Testimony in Docket No. UE 400. Based on that estimate, I calculate a revenue requirement reduction of $7,359,807, attributable to including the Utah Schedule 34 customer load in Utah's allocation factor. This is an estimate, since the precise load of the Utah Schedule 34 customer is unknown, and the impact will have to be applied to all adjustments and aspects of PacifiCorp's filing. Stated differently, PacifiCorp's proposed allocation represents the stranded costs that the Utah Schedule 34 customer would not pay as a result of its special contract with PacifiCorp, which my adjustment reverses.

p. <u>Utah DSM Allocation</u>

Q. PLEASE SUMMARIZE THE ISSUE YOU RAISED IN THE TAM RELATED TO THE UTAH DSM PROGRAM.

A. I recommended that the adjustment for the Utah DSM program be eliminated from Utah's allocation factors. The load forecast that PacifiCorp prepares already considers the specific customer use for the Utah DSM program, therefore an adjustment to the loads used to calculate Utah's dynamic load-based allocation factors is unnecessary. Further, Oregon customers do not receive a benefit for Utah DSM programs, which was another reason to exclude the adjustment from Utah's allocation factors.

Q. DID YOU REQUEST THE WORKPAPERS TO REVIEW HOW THE UTAH DSM PROGRAM WAS CONSIDERED IN THE LOAD FORECAST?

A. Yes. In AWEC Data Request 70, PacifiCorp was requested to provide all workpapers used to develop its load forecast. In response, PacifiCorp referenced the testimony support workpapers of Kenneth Lee Elder, Jr, which merely contained the tables, with hard coded values supporting witness Elder's testimony. Therefore, PacifiCorp has not provided any information to support the accuracy of its load forecast. Further, even if an adjustment were necessary for the Utah DSM program, PacifiCorp modeled the entire capacity of the program as an adjustment, whereas only a minor fraction of that amount may be used to offset system peaks. The air conditioner curtailments only last a few minutes, for example, and PacifiCorp is not capable of calling the entire program for the entire hour. PacifiCorp provided a history of curtailments in response to AWEC Data Request 66.

Further, much of the curtailed load may not have been online anyway during the curtailment. Air conditioners do not run all the time and a curtailment applied when an air conditioner is not running has no impact on peak load. Finally, even in the case where there is a curtailment, the air conditioner will otherwise cycle back on when the curtailment is completed, resulting in an increase to load following the curtailment, whereas the air conditioner would have otherwise cycled off. Thus, PacifiCorp's approach is not only duplicative of customer use reductions embedded in the load forecast, but it severely overvalues the capability of the program to satisfy capacity requirements. As noted in response to AWEC Data Request 63, PacifiCorp assumes that over 250 MW of capacity can be provided by the program, whereas only a fraction of that amount may be relied upon in any given hour.

Q. WHAT IS THE IMPACT OF REMOVING THE UTAH DSM ADJUSTMENT FROM UTAH'S ALLOCATION FACTORS.

A. Eliminating the Utah DSM adjustment from Utah's allocation factors results in an approximate $9,096,791 reduction to revenue requirement.

III. ANNUAL POWER COST ADJUSTMENT

Q. PLEASE SUMMARIZE PACIFICORP'S PROPOSAL TO MODIFY THE TAM AND PCAM.

A. PacifiCorp proposes to introduce "a rate-year update to the [TAM]" and to modify the foundation of the hydrological information used in the net power cost forecast.[10] PacifiCorp also proposes three changes to the PCAM.[11] First, the Company proposes to adjust the deadbands "to be symmetrical by moving the upper deadband from $30 million to $15 million."[12] Second, PacifiCorp proposes to set "the earnings test at PacifiCorp's authorized ROE," and third, the Company proposes that it "may propose that the NPC costs of certain months be recovered outside the deadbands, sharing bands, and earnings test."[13]

Q. HAS PACIFICORP PREVIOUSLY PROPOSED CHANGES TO THE TAM AND PCAM?

A. Yes. There is extensive Commission precedent related to PacifiCorp's numerous attempts to whittle down the TAM, PCAM, and the customer protections associated with these two mechanisms. Most recently, in PacifiCorp's last general rate case, the Company proposed to combine the TAM and PCAM into a single filing, remove the PCAM deadbands, sharing, earnings test, and update the TAM guidelines.[14] The Commission declined to adopt all of PacifiCorp's proposals, explaining that the Company failed to "demonstrate[] a fundamental change in the risk balance between customers and the company that occurs with its power costs."[15] The Commission further found that the Company failed to show redesign was

[10] PAC/400 Wilding/2:5-7.
[11] *Id.* at 11:5-10.
[12] *Id.* at 11:6-7.
[13] *Id.* at 11:8-10.
[14] Docket No. UE 374, Order No. 20-473, at 125 (Dec. 18, 2020).
[15] *Id.* at 129.

necessary.[16] Similarly, in Docket No. UE 246, PacifiCorp attempted to combine the TAM and PCAM, which the Commission declined to do.[17]

a. <u>Rate-Year Update</u>

Q. PLEASE ELABORATE ON PACIFICORP'S TAM PROPOSAL.

A. PacifiCorp proposes an update to the TAM take place during the rate-year that would "update [forecast net power costs] to the latest official forward price curve, includ[ing] the latest short-term purchases and sales, and the most recent hydrologic forecast for the test-year."[18] The rate-year update would require a filing on March 1, and PacifiCorp proposes an effective date for updated rates of April 1.[19] According to the Company, the purpose of the change "is to update NPC to incorporate the latest information and costs that are necessary to meet PacifiCorp's resource adequacy requirements for the Western Power Pool's ("WPP") Western Resource Adequacy Program ("WRAP")."[20]

Q. DO YOU AGREE WITH PACIFICORP'S TAM RATE-YEAR UPDATE PROPOSAL?

A. No. The Commission should reject PacifiCorp's rate-year update proposal because it would result in another rate change within a year and unreasonably shifts risk associated with the NPC forecast from PacifiCorp to ratepayers. A rate-year update as proposed by the Company increases rate variability, thereby resulting in increased uncertainty for customers, a particular concern for AWEC's commercial and industrial ratepayer constituency.

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16 *Id.*
17 *See* Docket No, UE 246, Order No. 12-493, at 14 (Dec. 20, 2012).
18 PAC/400 Wilding/5:1-2.
19 *Id.* at 5:4-5, 9.
20 *Id.* at 5:11-14.

Q. DOES A RATE YEAR UPDATE ADVANCE THE PURPOSE OF THE TAM?

A. No. The original purpose of the TAM, as the eponym implies, was to calculate transition adjustments for direct access customers. The update to the NPC base line was necessary to align the rates that were being paid by cost-of-service customers and the transition adjustments paid by direct access customers. If there was a mismatch between the rates paid by cost-of-service customers and direct access customers, that would produce potential arbitrage opportunities for switching between direct access and cost of service rates, so it was important for both cost-of-service and direct access rates to be developed in tandem. Under PacifiCorp's proposal, the purpose and structure of the TAM would balloon into an unwieldy process in which intervenors are litigating aspects of the coming year's filing, at the same time as investigating the accuracy of the prior-year's update during the mid-year update process. The current TAM process is not broken, and therefore, there is no reason to make wholesale changes to it. Problems with PacifiCorp's forecasting are better addressed through simplicity, rather than layering on additional complications to an already complicated process.

Q. IF RATES ARE UPDATED MID-YEAR, IS IT NECESSARY FOR A NEW DIRECT ACCESS OPT-OUT WINDOW?

A. Yes. If there is to be an update mid-year, it would also be necessary for PacifiCorp to recalculate the transition adjustments and to offer a new opt-out window for direct access customers. Absent such an opportunity, there will be a mismatch between the transition adjustment rates and the cost-of-service rates.

b. <u>Hydrological Forecasting</u>

Q. DOES PACIFICORP PROPOSE ANY OTHER CHANGES TO THE TAM?

A. Yes. PacifiCorp additionally proposes to modify the TAM guidelines to permit "using forecast hydro generation in place of the normalized hydro generation that is used today for the Lewis

River hydro project."[21] As I understand the Company's proposal, PacifiCorp proposes to use normalized hydrologic data for the initial TAM filing and then "replace normalized forecast data with …rate year specific hydrologic information…to calculate hydro generation in the rebuttal, indicative, final, and Rate-Year Updates for the TAM."[22]

Q. DO YOU AGREE WITH THESE ADDITIONAL CHANGES?

A. No. PacifiCorp develops its normalized forecast data with "[h]istorical annual median flow…calculated based on the flow data available since 1929."[23] PacifiCorp correctly stated in direct testimony that, "[h]ydrological conditions and operational requirements change over time[.]"[24] A specific year forecast eliminates the smoothing effect of a normalized forecast and has the potential to increase volatility in the annual NPC adjustment. Utilizing more data, as is currently used, rather than less, as proposed by PacifiCorp, decreases potential volatility in the NPC forecast. I recommend PacifiCorp continue to use normalized forecast data.

Q. IS IT POSSIBLE TO DEVELOP A REASONABLE FORECAST OF HYDROLOGICAL CONDITIONS IN THE TAM?

A. No. Hydrological conditions for a water year tend to be highly variable, particularly in the timeframe when the TAM is being developed. As of November, the water conditions for the coming year are not knowable. Water conditions in the summer are usually not knowable until the spring timeframe, as precipitation in February and March, as well as the timing of the spring runoff, tends to have the largest impacts on hydro conditions.

[21] *Id.* at 6:15-16.
[22] *Id.* at 6:19-21.
[23] *Id.* at 7:5-6.
[24] *Id.* at 9:15.

Q. DOES INTRODUCTION OF A NON-NORMALIZED HYDROLOGICAL FORECAST BRING OTHER ASPECTS OF NET POWER COST INTO QUESTION?

A. Yes. Introducing non-normalized hydrological variables into the TAM, through either its indicative filing or a rate year update, will call into question all normalized aspects of PacifiCorp's filing. Departing from normalization has the potential to be a slippery slope. Consider for instance, the relationship between forecast hydrological conditions and loads. If forecast hydrological conditions were incorporated into the TAM, it would also be logical to incorporate the impacts of those conditions on loads. Similarly, consider the relationship between hydrological conditions and production from wind and solar resources. In a year with more precipitation, there may be more or less output from such resources.

Q. WHAT TYPE OF REVIEW WOULD BE NECESSARY TO CONSIDER FORECAST HYDROLOGICAL CONDITIONS?

A. Introducing a hydrological forecast would also expand the scope of subject matter reviewed in the TAM to include not just production cost modeling, but also metrological modeling. This may require, for example, the Commission to hire a meteorologist, which may not be pragmatic, given the marginal benefits of such a process change. The hydrological forecast will require the Commission to analyze complex metrological relationships, such as the correlation between sea surface temperature in the north Pacific and snowfall at timberline. There is also the impact of the famed butterfly that flapped its wings, which only goes to demonstrate that the chaotic relationships between weather phenomenon are difficult to predict. While I understand Idaho Power uses a river forecast to inform their final power cost updates, Idaho Power's circumstances are unique, in that their system is more dependent on hydro output and due to the timing of their filings, which occur in the spring. AWEC does not intervene in Idaho Power cases, and does not necessary agree with the structure of their update process. Rather than introducing a new subject matter into the TAM, the Commission is best suited to focus on traditional production cost modeling using a normalized net power costs forecast.

c. <u>TAM Guidelines</u>

Q. WHAT OTHER CHANGES DOES PACIFICORP PROPOSE TO THE TAM?

A. PacifiCorp proposes to "incorporate the elements from various TAM Orders into the TAM Guidelines to allow for the codification of all the changes that have occurred since the TAM Guidelines were originally adopted."[25]

Q. DO YOU AGREE WITH THESE ADDITIONAL CHANGES?

A. While AWEC does not oppose updating the TAM Guidelines to reflect previous TAM Orders, AWEC recommends that if the Commission does adopt PacifiCorp's proposal, all TAM Guidelines be restated in whole so that they are not included piecemeal in various orders. Having all TAM Guidelines restated in a single Order supports a clear understanding for the Commission, PacifiCorp, and stakeholders involved in future proceedings and will further support the uniform application of requirements going forward.

Q. DO YOU HAVE ANY PROPOSED CHANGES FOR THE TAM GUIDELINES FOR THE COMMISSION TO CONSIDER?

A. Yes.

First, I recommend the use of a seven-calendar day discovery window beginning with PacifiCorp's initial filing. Due to extended discovery windows, the ability to conduct a meaningful review has also been hampered. Assuming an April filing, intervenors only have two months to conduct discovery. With a two week turn around on discovery, leaving some

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[25] *Id.* at 10:14-16.

time to review and process the responses received and to prepare testimony, intervenors realistically often only have the opportunity to conduct two rounds of discovery during the review period. Often, however, it takes multiple rounds of discovery for PacifiCorp to provide meaningful responses to requests. Many times, for example, PacifiCorp provides workbooks that are irrelevant or have all of the formulas removed, making follow-up requests necessary. A number of these examples were cited in my Opening Testimony in Docket No. UE 400. This long discovery window is compounded by the fact that many of the workpapers are not filed until 15 days following PacifiCorp's filing.

Second, I recommend the filing date in years without a general rate case be moved to March 1, rather than April 1. This will provide intervenors with greater opportunity to review PacifiCorp's filing. With PacifiCorp's move to the AURORA model, the complexity and difficulty in analyzing the filings has increased. Depending on one's processing speeds, it can take over 24 hours to conduct a single modeling run in the AURORA model. Thus, adding more time to the review process will better enable parties to conduct a robust review.

Third, I recommend that future TAM filings use a base period that corresponds to the calendar year prior to the filing. The current TAM framework uses a base period corresponding to the year ending in June of the calendar year prior to the filing. This results in the use of outdated data, which is unnecessary, since all of the data is available at the time PacifiCorp makes its filings. PacifiCorp has invested in energy trading software and the AURORA model, which makes the data necessary to complete the TAM based on calendar year data more accessible, so the need to use an outdated base period is no longer pressing.

Finally, I recommend that PacifiCorp be required to submit an October update, by October 10th, with an update to its September OFPC, updated contracts, and any other items that

PacifiCorp intends to consider in its final update. This will provide parties the opportunity to review new contracts and modeling updates prior to the final indicative updates in November. There is usually limited time and ability to review and challenge updates in the November update, so introducing an October update will provide parties with a fair opportunity to review and potentially object to such changes.

d. Power Cost Adjustment Mechanism

Q. HAS THE COMMISSION SET FORTH GENERAL PRINCIPLES FOR THE PCAM?

A. Yes. As explained by the Commission when approving PacifiCorp's PCAM, there are five general principles that "that form the basis of a well-designed PCAM:"[26]

> (1) any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility; (2) there should be no adjustments if the utility's overall earnings are reasonable; (3) the PCAM's application should result in revenue neutrality; (4) the PCAM should operate in the long-term to balance the interests of the utility shareholder and ratepayer; and, implicitly, (5) the PCAM should provide an incentive to the utility to manage its costs effectively."[27]

Q. HOW ARE THESE PRINCIPLES IMPLEMENTED THROUGH THE PCAM?

A. First, the Commission established a deadband so that the utility "would absorb some normal variation of power costs."[28] The deadband is asymmetric "[t]o ensure the PCAM [is] revenue-

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26 Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012).
27 *Id.* (internal citations omitted).
28 *Id.*

neutral."[29] Second, the Commission adopted a sharing mechanism that provides the utility "'with an incentive to manage its costs effectively, while sharing costs that are beyond normal business risk.'"[30] Finally, the Commission applied an earnings test "to determine whether the utility is earning an acceptable ROE."[31] The earnings test is specifically in place "to protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable, while protecting the utility from refunding power cost savings when it is under-earning."[32]

Q. DO YOU RECOMMEND THE COMMISSION CONSIDER PACIFICORP'S PCAM PROPOSALS IN THIS CASE?

A. No. The facts and circumstances have not changed in the short time since PacifiCorp requested, and the Commission rejected, proposed changes to the PCAM in Docket No. UE 374. Rather than asking the Commission to rehear all of the same issues and arguments, I recommend the Commission decline to consider the issue. The Commission does not have to consider every issue addressed in a docket and it is not reasonable for the Commission to assume the administrative burden to reconsider an issue from a case that was recently litigated and decided. Therefore, I recommend the Commission decline to consider the PCAM changes altogether.

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29 *Id.*
30 *Id.* at 14 (internal citations omitted).
31 *Id.*
32 *Id.*

Q. HOW DO YOU RESPOND TO PACIFICORP'S PROPOSED PCAM DEADBAND ADJUSTMENT?

A. AWEC opposes PacifiCorp's proposed deadband adjustment. As PacifiCorp notes, the Company's proposal in this case is "inspired" by its proposal from Docket No. UE 374, [33] which the Commission rejected.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED DEADBANDS?

A. Yes. In effectuating the principles associated with the PCAM, the Commission "established a deadband, so that [the utility] would absorb some normal variation of power costs."[34] According to the Commission, "[t]o ensure the PCAM is revenue neutral, [the Commission] adopt[ed] an asymmetric deadband, with a negative annual power cost variance deadband of $15 million, and a positive annual power cost variance deadband of $30 million."[35] The $15 million and $30 million deadband thresholds were based on PacifiCorp's rate base and authorized ROE, rather than NPC.[36] The Commission explained that "[i]n determining an appropriate power cost deadband, [the Commission] look[s] to the size of the utility's authorized ROE."[37]

Q. WHAT IS PACIFICORP'S JUSTIFICATION IN SUPPORT OF SYMMETRICAL DEADBANDS.

A. According to PacifiCorp, symmetrical deadbands are reasonable because of changed conditions, including changes "related to resource mix, supply and demand, macroeconomic factors, technology adoption and change, environmental policy changes, as well as climate

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33 PAC/400 Wildling /23:4-5.
34 Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012).
35 *Id.* at 15.
36 *Id.*
37 *Id.*

change related impacts and associated mitigation strategies."[38] PacifiCorp asserts that these changes have negatively affected the Company's ability to forecast power costs due to decreased certainty.[39] Therefore, the Company argues that symmetrical deadbands will "help PacifiCorp to rebalance the risk between customers and the Company" because it would "allow customers and shareholders to share costs and risks" and "increase the likelihood of adjustments to the mechanism."[40]

Q. HAVE CIRCUMSTANCES CHANGED TO WARRANT CHANGES TO THE PCAM?

A. No. AWEC does not disagree that conditions such as those noted by PacifiCorp are evolving. However, any changes to these conditions do not warrant deviation from the current PCAM structure. Adoption of PacifiCorp's proposal would frustrate the general principles associated with the PCAM. The PCAM is currently structured to balance the interests of shareholders and customers in the long-term and limit adjustments under a PCAM to variances outside of normal business risk for the utility. None of the circumstances put forth by PacifiCorp as justification reflect unusual events and therefore any power cost variances are within normal business risk. Moreover, as noted above, the Commission established the current deadband structure based on the utility's authorized ROE.[41] PacifiCorp has failed to address why the positive annual power cost variance should be modified in favor of the Company, while at the same time PacifiCorp requests an increase to its authorized ROE.

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38 PAC/400 Wildling/12:8-11.
39 *Id.* at 20:8-11.
40 *Id.* at 23:1-8 (internal citations omitted).
41 Docket No. UE 246, Order No. 12-493, at 15 (Dec. 20, 2012).

Q. HOW DO YOU RESPOND TO PACIFICORP'S PROPOSAL TO SET THE EARNINGS TEST AT THE COMPANY'S AUTHORIZED ROE?

A. AWEC opposes PacifiCorp's earnings test proposal. PacifiCorp argues that "by setting the earnings test at PacifiCorp's authorized ROE, and keeping the deadbands, it still ensures that rate adjustments only occur for significant NPC variations."[42] However, the Commission specifically adopted "an earnings test of +/- 100 basis points around PacifiCorp's allowed ROE" in order to "protect customers from paying higher-than-expected power costs when the utility's earnings are reasonable, and to protect [PacifiCorp] from refunding power cost savings when it is under-earning[.]"[43] Rate regulation does not guarantee a utility the ability to earn its authorized return, only an opportunity to earn that return. Thus, an earnings test established within 100 basis points of the authorized ROE reflects that opportunity, rather than guarantee. PacifiCorp has not addressed the Commission's underlying rationale for the earnings test design nor explained why it is no longer applicable.

Q. HOW DO YOU RESPOND TO PACIFICORP'S PROPOSAL THAT IT MAY PROPOSE THAT THE NPC COSTS OF CERTAIN MONTHS TO BE RECOVERED OUTSIDE THE DEADBANDS, SHARING BANDS, AND EARNINGS TEST?

A. AWEC opposes allowing recovery of costs without the protections of the existing deadbands, sharing bands, and earnings test. PacifiCorp asserts that this adjustment "is intended to introduce more flexibility into the PCAM" and would allow the Company "to identify certain specific and unusual months that resulted in significant costs and therefore a significant deviation from the NPC baseline forecast for that month."[44] However, the first principle that forms a well-designed PCAM addresses this exact issue, "any adjustment under a PCAM

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42 PAC/400 Wildling/24:3-5.
43 Docket No. UE 246, Order No. 12-493, at 15 (Dec. 20, 2012).
44 PAC/400 Wilding/24:8-11.

should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility."[45] Deadbands, sharing bands, and the earnings test are fundamental to the PCAM and have been specifically adopted and reaffirmed by the Commission as necessary for a "well-designed PCAM," which the Commission has found to be "the most prudent way to accomplish proper recovery." [46]

Further, PacifiCorp's proposal appears to require an additional proceeding within the PCAM mechanism, in which stakeholders review costs and present testimony on a case-by-case basis.[47] Not only does PacifiCorp's proposal fly in the face of the principles associated with a well-designed PCAM, but it also requires additional resources and increases the administrative burden on the Commission and stakeholders. The TAM and PCAM framework continue to operate as designed by the Commission and should not be modified without ensuring that the existing customer protections are maintained.

Q. DO YOU HAVE ANY FINAL COMMENTS ON PACIFICORP'S PROPOSED CHANGES TO THE TAM AND PCAM?

A. Yes. It is worth remembering that the TAM and PCAM were initially created in part to help PacifiCorp manage its risk. Prior to these mechanisms, PacifiCorp's only opportunity to modify its power cost forecast was in a general rate case, and it had no opportunity to recover larger-than-normal variations in power costs, other than through a deferral. The TAM now allows PacifiCorp to update its power cost forecast annually, thus reducing its risk, and the PCAM gives it a built-in true-up mechanism that allows it to recover abnormal power costs from customers. If the Commission is to consider any of the changes that PacifiCorp

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45 *See* Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012).
46 *Id.*
47 PAC/400 Wilding/24:18-23.

recommends, it should also reduce PacifiCorp's return on equity to account for the lower risk the utility is assuming.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

MW ANALYTICS
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ABOUT

MW Analytics is the professional consulting practice of Brad Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the Western United States. Brad has sponsored expert witness testimony in over 90 regulatory proceeding encompassing a variety of subject matters, including revenue requirement, regulatory accounting, rate development, and new resource additions. Brad has also assisted his clients through informal regulatory, legislative and energy policy matters. In addition to providing regulatory services, MW Analytics also provides advisory, energy marketing and other energy consulting services.

PRACTICE AREAS

MW Analytics has experience representing customer interests in litigated and informal regulatory proceedings, including the following subject areas:

- Revenue Requirement
- Power Cost Modeling
- Tax Provisions and Tax Reform
- Capital Additions and Forecasting
- Regulatory Accounting
- Depreciation Studies
- Pole Attachments
- Integrated Resource Planning
- Avoided Cost Calculations
- Utility Plant Retirements

EDUCATION AND WORK EXPERIENCE

Brad has a Master of Accounting degree from the University of Utah. After obtaining his master's degree, Brad worked at Deloitte Tax in San Jose, California, where he was responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients. Brad was later promoted to a Tax Senior position in a national tax practice specializing research and development tax credit studies. Following Deloitte, Brad worked at PacifiCorp Energy, as an analyst involved in power cost modeling and forecasting. At PacifiCorp Brad was responsible for preparing power cost forecasts and supporting testimony for regulatory filings, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations.

REGULATORY APPEARANCES

Brad has sponsored expert witness testimony in the following regulatory proceedings:

Docket	Party	Topics
In re the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the cost recovery of the regulatory assets relating to the development and implementation of their Joint Natural Disaster Protection Plan., PUC NV. Docket No. 22-03006.	Alliance of Western Energy Consumers	Single-Issue Rate Filing
In re PacifiCorp d.b.a. Pacific Power, 2023 Transition Adjustment Mechanism, Or.PUC Docket No. UE 399.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Cascade Natural Gas Corporation, Request for a General Rate Revision, Wa.UTC Docket No. UG-210755	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service

Docket	Party	Topics
In re Northwest Natural Gas Company, dba NW Natural, Request for A General Rate Revision, Or.PUC. Docket No. UG 435	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service
In re Formal Complaint of Tree Top Inc. against Cascade Natural Gas Corporation, Wa.UTC Docket No. UG-210745	Tree Top, Inc.	Overrun Entitlement
In re Northwest Natural Gas Company, dba NW Natural, Request for Approval of an Affiliated Interest Agreement with Lexington Renewables, LLC, Or.PUC. Docket No. UI 451.	Alliance of Western Energy Consumers	Affiliated Interest
In re Avista Corporation, Request for a General Rate Revision, Or.PUC Docket No. UG 433	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service
In re PacifiCorp Power Cost Only Rate Case, Wa.UTC Docket No. UE-210402.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp Limited Issue Rate Filing, Wa.UTC Docket No. UE-210532.	Alliance of Western Energy Consumers	Revenue Requirement / Settlement
In re the Application of Rocky Mountain Power for Authority to Increase Its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations, Id.PUC Case No. PAC-E-21-07.	PacifiCorp Idaho Industrial Customers	Revenue Requirement / Settlement
In re Portland General Electric, Request for a General Rate Revision, Or.PUC Docket No. UE 394.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their Economic Recovery Transportation Electrification Plan for the period 2022-2024, PUC Nv. Docket No. 21-09004	Nevada Resort Association	Transportation Electrification
In re PacifiCorp, dba Pacific Power, 2020 Power Cost Adjustment Mechanism, Or.PUC Docket No. UE 392.	Alliance of Western Energy Consumers	Power Cost Deferral
In re the Application of Rocky Mountain Power for Authority to Decrease Current Rates by $14.9 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $166 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-599-EM-21.	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re Portland General Electric 2021 Annual Update Tariff Schedule 125, Or. PUC Docket No. UE 391.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of a regulatory asset account to recover costs relating to the development and implementation of their Joint Natural Disaster Protection Plan, PUC NV. Docket No. 21-03004.	Wynn Las Vegas, LLC; Smart Energy Alliance	Single-Issue Rate Filing
In re PacifiCorp d.b.a. Pacific Power, 2022 Transition Adjustment Mechanism, Or.PUC Docket No. UE 390.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Avista 2020 General Rate Case, Wa.U.T.C. Docket No. UE-200900 (Cons.).	Alliance of Western Energy Consumers	Revenue Requirement
In re NV Energy's Fourth Amendment to Its 2018 Joint Integrated Resource Plan, PUC Nv. Docket No 20-07023.	Wynn Las Vegas, LLC; Smart Energy Alliance	Transmission Planning
In Re Cascade Natural Gas Corporation, 2020 General Rate Case, Wa.U.T.C. Docket No. UG-200568	Alliance of Western Energy Consumers	Revenue Requirement
In re Cascade Natural Gas Corporation, Petition to File Depreciation Study, Or.PUC Docket No. UM 2073	Alliance of Western Energy Consumers	Depreciation Rates
In re the Application of Rocky Mountain Power for Authority to Increase Current Rates By $7.4 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates by $604 Thousand Under Tariff Schedule 93, Rec and So2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-582-EM-20	Wyoming Industrial Energy Consumers	Power Cost Deferral

Docket	Party	Topics
In re the Complaint of Willamette Falls Paper Company and West Linn Paper Company against Portland General Electric Company, Or.PUC Docket No. UM 2107	Willamette Falls Paper Company	Consumer Direct Access, Tariff Dispute
In re The Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4, Wy.PSC Docket No. 2000-578-ER-20	Wyoming Industrial Energy Consumers	Power Cost Modeling
Avista Corporation 2021 General Rate Case, Or.PUC Docket No. UG 389	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re NW Natural Request for a General Rate Revision, Or.PUC Docket No. UG 388.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.	Alliance of Western Energy Consumers	Jurisdictional Allocation
In re Puget Sound Energy 2019 General Rate Case, Wa.UTC Docket No. UE 190529.	Alliance of Western Energy Consumers	Revenue Requirement, Coal Retirement Costs
Avista Corporation 2020 General Rate Case, Wa.UTC Docket No. UE-190334 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Application for Approval of a Safety Cost Recovery Mechanism, Or. PUC Docket No. UM 2026.	Alliance of Western Energy Consumers	Ratemaking Policy
In re Avista Corporation, Request for a General Rate Revision, Or.PUC Docket No. UG 366.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric, 2020 Annual Update Tariff (Schedule 125), Or.PUC Docket No UE 359.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Transition Adjustment Mechanism, Or.PUC Docket No. UE 356.	Alliance of Western Energy Consumers	Power Cost Modeling
In re PacifiCorp 2020 Renewable Adjustment Clause, Or.PUC Docket No. UE 352.	Alliance of Western Energy Consumers	Single-Issue Rate Filing
2020 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-20.	Alliance of Western Energy Consumers	Revenue Requirement, Policy
In the Matter of the Application of MSG Las Vegas, LLC for a Proposed Transaction with a Provider of New Electric Resources, PUC Nv. Docket No. 18-10034	Madison Square Garden	Customer Direct Access
Puget Sound Energy 2018 Expedited Rate Filing, Wa.UTC Dockets UE-180899/UG-180900 (Cons.).	Alliance of Western Energy Consumers	Revenue Requirement, Settlement
Georgia Pacific Gypsum LLC's Application to Purchase Energy, Capacity, and/or Ancillary Services from a Provider of New Electric Resources, PUC Nv. Docket No. 18-09015.	Georgia Pacific	Customer Direct Access
Joint Application of Nevada Power Company d/b/a NV Energy for approval of their 2018-2038 Triennial Integrated Resource Plan and 2019-2021 Energy Supply Plan, PUCN Docket No. 18-06003.	Smart Energy Alliance	Resource Planning
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Or.PUC, Docket No. UE 347.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Portland General Electric Company Request for a General Rate Revision, Or.PUC Docket No UE 335.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket No. UG 344.	Alliance of Western Energy Consumers	Revenue Requirement, Rate Design
In re Cascade Natural Gas Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170929.	Northwest Industrial Gas Users	Revenue Requirement, Rate Design

Docket	Party	Topics
In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation, Or.PUC, Docket No. UM 1897.	Alliance of Western Energy Consumers	Merger
Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision, Ut.PSC Docket No. 17-035-40	Utah Industrial Energy Consumers, & Utah Associated Energy Users	New Resource Addition
In re PacifiCorp, dba Rocky Mountain Power, for a CPCN and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Id.PUC Case No. PAC-E-17-07	PacifiCorp Idaho Industrial Customers	New Resource Addition
In re PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE 327.	Alliance of Western Energy Consumers	Power Cost Deferral
In re PacifiCorp 2016 Power Cost Adjustment Mechanism, Wa.UTC Docket No. UE-170717	Boise Whitepaper, LLC	Power Cost Deferral
In re Avista Corporation 2018 General Rate Case, Wa.UTC Dockets UE-170485 and UG-170486 (Consolidated).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUCN. Docket No. 17-06003.	Smart Energy Alliance	Revenue Requirement
In re the Application of Rocky Mountain Power for Authority to Decrease Current Rates by $15.7 Million to Refund Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Decrease Current Rates By $528 Thousand Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy. PSC, Docket No. 20000-514-EA-17 (Record No. 14696).	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. UE-170033 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.	Industrial Customers of Northwest Utilities	Electric Vehicle Charging
In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.	Industrial Customers of Northwest Utilities	Qualifying Facilities
In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company's existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.	Boise Whitepaper, LLC	Customer Direct Access
In re Puget Sound Energy's Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.	Industrial Customers of Northwest Utilities	Customer Direct Access
2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy
In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).	Industrial Customers of Northwest Utilities	Environmental Deferral

Docket	Party	Topics
In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.	Arkansas Electric Energy Consumers	Net Metering
In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.	Arkansas Electric Energy Consumers	Net Metering
In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01	Utah Associated Energy Users	Power Cost Deferral
In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).	Industrial Customers of Northwest Utilities, & Northwest Industrial Gas Users	Revenue Requirement, Rate Design
In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.	Wyoming Industrial Energy Consumers	Power Cost Deferral
Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.	Columbia Rural Electric Association	Customer Direct Access / Customer Choice
In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.	Industrial Customers of Northwest Utilities	Power Cost Deferral
In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.	Industrial Customers of Northwest Utilities	Resource Planning
In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.	Industrial Customers of Northwest Utilities	Revenue Requirement, Policy

Docket	Party	Topics
In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.	Industrial Customers of Northwest Utilities	Cost of Service
In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.	Boise Whitepaper, LLC	Revenue Requirement, Rate Design
In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.	Wyoming Industrial Energy Consumers	Power Cost Modeling
In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design, Power Costs
In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.	Industrial Customers of Northwest Utilities	Single-issue Ratemaking
In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.	Industrial Customers of Northwest Utilities	Revenue Requirement, Rate Design
In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.	Industrial Customers of Northwest Utilities	Power Cost Modeling
In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.	Industrial Customers of Northwest Utilities	Coal Retirement
In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.	Industrial Customers of Northwest Utilities	Customer Direct Access

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

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Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/102

REVENUE REQUIREMENT SUMMARY

Electric Revenue Requirement Summary ($000)

Line	Adj. No.	Description	Revenue Requirement: Net Oper. Income	Revenue Requirement: Rate Base	Revenue Requirement: Rev. Req. Def. / (Suf.)	Impact of AWEC Adjustments: Pre-Tax Net Oper. Income	Impact of AWEC Adjustments: Net Oper. Income	Impact of AWEC Adjustments: Rate Base	Impact of AWEC Adjustments: Rev. Req. Def. / (Suf.)
1		**Initial Filing**	**$190,246**	**$4,199,122**	**154,373**				
2		Less TAM Revenues	**$241,286**	**$4,199,122**	**84,399**	$67,680	$51,040	$0	(69,974)
3									
Adjustments:									
4	A1	Cost of Capital (Gorman)	$241,286	$4,199,122	64,240	-	-	-	(20,160)
5	A2	Tax Benefit of BHE Interest	$248,742	$4,199,122	54,018	$9,887	7,456.09	-	(10,222)
6	A3	State NOL Carryforwards	$248,742	$4,180,920	52,305	-	-	(18,202)	(1,712)
7	A4	Inj. & Damages DTA	$248,742	$4,177,867	52,018	-	-	(3,053)	(287)
8	A5	Environmental Reg. Assets	$249,913	$4,168,465	49,528	1,553	1,171	(9,402)	(2,490)
9	A6	Insurance Expense	$252,267	$4,168,465	46,302	3,121	2,354	-	(3,227)
10	A7	Trapper Mine - Reclamation	$252,267	$4,166,485	46,115	-	-	(1,980)	(186)
11	A8	Trapper Mine - Prudence	$252,267	$4,165,463	46,019	-	-	(1,022)	(96)
12	A9	Fuel Stock - Forecast	$252,267	$4,161,868	45,681	-	-	(3,594)	(338)
13	A10	Fuel Stock - Rock Garden	$252,267	$4,153,989	44,940	-	-	(7,879)	(741)
14	A11	Meter Replacement Amortization	$252,996	$4,153,989	43,940	967	729	-	(1,000)
15	A12	Prepayments	$252,996	$4,113,955	40,174	-	-	(40,034)	(3,766)
16	A14	Old Mobile Radio	$252,996	$4,109,884	39,791	-	-	(4,071)	(383)
17	A15	Wind Projects Deferral	$257,627	$4,109,884	33,442	6,140	4,631	-	(6,349)
18	A16	Fly Ash Deferral	$259,059	$4,109,884	31,479	1,899	1,432		(1,963)
19	A17	Utah Schedule 34	$261,436	$4,066,289	24,119	3,152	2,377	(43,595)	(7,360)
20	A18	Utah DSM	$264,393	$4,012,690	15,022	3,922	2,957	(53,599)	(9,097)
21	A19	Coal Depr. Lives (Kaufman)	$275,856	$4,012,690	(693)	15,200	11,463	-	(15,715)
22	A20	Rolling Hills (Kaufman)	$277,440	$4,012,690	(2,864)	2,100	1,584	-	(2,171)
23	A21	Wildfire Disallowance (Kaufman)	$278,496	$4,012,690	(4,312)	1,400	1,056	-	(1,447)
24	A20	Interest Coordination	$277,511	$4,012,690	(2,962)		(985)		1,350
25		**Adjusted Results**	**$277,511**	**$4,012,690**	(2,962)	**117,021**	**87,265**	**(186,431)**	**(157,335)**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/103

REDACTED RESPONSES TO DATA REQUESTS

AWEC Data Request 02

Reference Cheung work paper "B16 - Regulatory Assets," Account "1823910 - ENVIR CST UNDR AMORT": The referenced account includes regulatory assets of $9,402,000 allocated to Oregon. For each item in the referenced account with Oregon-allocated amounts, please provide a brief description of the item and identify the Commission order where the regulatory asset was approved.

Response to AWEC Data Request 02

Please refer to Attachment AWEC 02 which provides a brief description of each referenced account included in Oregon's rate base. Environment Costs Regulatory Assets were approved as part of the settlement outcome in Oregon's general rate case (GRC), Docket UE 147. Since the 2003 GRC, this approved treatment of environmental costs being deferred and amortized over ten years has been continuously applied and approved in all subsequent GRCs.

Environmental Regulatory Asset Project Description	AWEC 03 Total Company Amortization ($)	AWEC 03 Oregon Allocation Amortization ($)	AWEC 02 Project Description
Alturas Service Center (CA)	850	225	As part of the development of the Spill Prevention, Control and Countermeasures plan for the site, it was noted that the discharge from an oil/water separator was directed to an offsite ditch for the collection of storm water. Due to the potential presence of contaminants in the discharge from the oil/water separator, soil samples will be collected to assess the potential for an offsite release. The estimated contingent liability includes costs for conducting the assessment.
American Barrel (UT)	67,014	17,471	The American Barrel property was the site of a manufactured gas plant between approximately 1887 and 1908 and was operated by several different companies during this period. From approximately 1911 through 1950 the site was used to store poles and to perform some pole treating. From the late 1950s through 1986 the site was leased to American Barrel to store drums awaiting refurbishing. The property has been owned by PacifiCorp or a predecessor company since 1887. The property was sold to Salt Lake City in April 2007 to allow for the construction of rail lines across the property. The remedial action was performed in 1995 and 1996 and consisted of excavating approximately 22,000 tons of contaminated soil. Following the excavation activities, an SVE system with groundwater depression was installed to treat residual contamination. The site is currently in monitored natural attenuation. In addition, a Brownfield development is occurring on the west side of the site.
Astoria Young's Bay Cleanup MGP	111,202	28,991	The former Astoria Young's Bay MGP and fuel-oil-powered steam electrical plant were constructed by Pacific Power & Light Company in 1921. The MGP was operated from 1921 to 1949, but was sold to and operated by an unrelated company from 1927 to 1949. Pacific Power & Light Company re-acquired and decommissioned the MGP in 1950, and from 1951 to 1986, operated a Service Center on the site. In 1986, the structure was demolished. The steam plant was operated by PP&L from 1922 to 1954. The steam plant remained on standby until 1968. It was demolished in 2000. The 8 acre site, consisting of uplands and tide flat, is located in northwest Clatsop County in Township 8 North, Range 10 West, Section 18. The site is currently owned by PacifiCorp.
Astoria/Unocal (Downtown)	156 420	40 779	PacifiCorp's predecessors, including Pacific Power & Light Company, owned and operated a manufactured gas plant on portions of the former Astoria Terminal Property in Astoria, Oregon, from circa 1888 to 1921, at which time the manufactured gas plant was decommissioned and the portion of the site then owned by Pacific Power & Light was sold to Unocal. Unocal operated a petroleum oil terminal on portions of this site to 1977, at which time the oil terminal was decommissioned. Non-aqueous phase liquids have been detected in the soil, groundwater, and sediment at concentration in excess of state regulatory levels. PacifiCorp and Unocal have entered into a Voluntary Cleanup agreement with the Oregon Department of Environmental Quality to investigate and remediate the site.
Big Fork Hydro Plant (MT)	64,114	16,715	Big Fork Hydro is a hydro facility located in Big Fork Montana. Investigation and remediation activities have been ongoing at an old substation located adjacent to the Swan River since 2000. The work was done under EPA oversite. The EPA issued a no further action letter associated with the remediation. The State of Montana requested that EPA conduct a field investigation to determine if PCBs from the facility impacted the adjacent river, ground water, or adjacent land. In 2013, PacifiCorp entered into a Voluntary Agreement with the Montana Department of Environmental Quality to formally close the site under a site specific risk based process. The Montana Department of Environmental Quality identified some data gaps in the site characterization and is requiring PacifiCorp to perform additional site characterization and remediation in order to meet acceptable risk based standards. Two outside environmental groups are following the site investigation and commenting on plans submitted to the state resulting in extended timing for approvals. PacifiCorp submitted a revised work plan for the performance of additional site characterization and remediation to the Montana Department of Environmental Quality in May 2015. The investigation/remediation plan is currently being negotiated with the state.
Bors Property (OR) - 2016	2 155	570	On November 22, 2016, PacifiCorp received notice that the Oregon Department of Environmental Quality planned to reopen a project that had been issued a No Further Action determination in July 2001. PacifiCorp is one of several potentially responsible parties that participated in the remediation of polychlorinated biphenyl (PCB) soil contamination at the site between 1997 and 2001. The site was reopened at the request of the current property owner because it was cleaned up to the existing standard of 1.2 parts per million for polychlorinated biphenyls back in 2001; the current cleanup standard for polychlorinated biphenyls is .230 parts per million. PacifiCorp s share of liability in 2001 was 4%.
Bridger Coal Fuel Oil Spill	75,742	19,746	The Bridger Mine lost approximately 1.5 to 2 million gallons of diesel oil into the subsurface. A recovery system was built and installed to recovery the free product.
Bridger FGD Pond 1 Closure	112,204	29,252	Jim Bridger Power Plant is located nine miles north of Point of Rocks, Wyoming. The plant has been in operation since 1974 producing electricity through coal-fired generation from four boilers. The plant uses sulfur dioxide scrubbers to remove contaminants from plant stack emissions. The scrubbers were installed at the plant in 1979 and spent FGD solutions from the scrubbers are discharged into two ponds located adjacent to the Evaporation Pond, north of the plant. FGD Pond 1 was constructed in 1979 and operated through 2002, when it reached capacity. This pond is lined with a compacted native material (clay) to minimize the seepage of FGD solutions through its bottom. FGD Pond 2 was expanded in 2003 to handle the scrubber waste for the next 30 years.
Bridger Plant - FGD Pond 1	34,105	8,891	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Bridger Plant - FGD Pond 2	2 590	675	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Bridger Plant Oil Spills	68,230	17,788	The Bridger Mine lost approximately 1.5 to 2 million gallons of diesel oil into the subsurface. A recovery system was built and installed to recovery the free product.
Carbon Ash Spill (UT) - 2016	437 510	114 060	On August 4, 2016, a significant precipitation event occurred at PacifiCorp s Carbon coal ash landfill located near Helper, Utah, in Panther Canyon. The storm event caused localized flash flooding in the canyon, overwhelmed the storm water controls in place at the site, and resulted in sediment and an estimated 2,370 cubic yards of coal ash entering the Price River below the landfill. During the event a large fraction of the storm water and suspended coal ash were diverted from the Price River into the Price Wellington Canal Company and the Carbon Canal Company settling ponds. PacifiCorp worked with the two Canal Companies to remove the ash and sediment from the settling ponds that was released during the storm event. All of the material from the ponds was removed and all the required work under the Stipulated Compliance Order has been completed and the order closed. The site management continues under a Site Management Plan to address the long term monitoring of the landfill to demonstrate no further releases will occur.
Cedar Steam Plant (UT)	6 956	1 813	The plant has been dismantled and all equipment has been removed from the property. An ash pile remained on the north side of Highway 14. The Cedar Steam Plant Project consisted of re-contouring the remaining ash to closely resemble the surround properties. A layer of top sol cover was placed over the entire reclamation site and native vegetation was planted on the site in 2011.
Cholla Ash-Flyash Pond	1 292	337	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Cline Falls - Hydro	14 299	3 728	Cline Falls is a hydro facility located in Cline Falls, Oregon. It consists of a small dam, a canal and flume, a powerhouse, a substation, and associated structures. PacifiCorp entered into a lease for the property with the Central Oregon Irrigation District in 1913. In 2006, PacifiCorp ceased generation at the site due to water right issues associated with the project. In anticipation of the lease expiration in 2013, PacifiCorp took steps to wind-down the project by removing the substation and powerhouse equipment and conducting a Phase II environmental assessment prior to relinquishing the facility to the Central Oregon Irrigation District. The Phase II Assessment conducted in 2013 found two small areas of contamination that require remediation. The original estimate of contingent environmental liability was based on removing the impacted soil in the two areas with oversight from the local county health department. Central Oregon Irrigation District, as the owner of the site was required to sign the conditional use permit with the County to perform the work. The Central Oregon Irrigation District refused to sign the permit. Central Oregon Irrigation District and PacifiCorp are now in a legal dispute over issues concerning the property including the remediation. To resolve the environmental issues, PacifiCorp entered into the Oregon Voluntary Cleanup Program in June 2015 to address the contamination at the property. Remediation under the Voluntary Cleanup Program will require additional site characterization and risk assessment for closure. The Voluntary Cleanup Program agreement is signed and the investigation and remediation work plan is being prepared.
Colstrip Pond	104 137	27 149	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.

Dave Johnston Oil Spill	143,131	37,315	In August 2010, the plant spilled approximately 2000 gallons of oil into the containment surrounding the ignition storage tank. During the clean up of the oil, it was discovered that the clay liner was saturated with oil. 20 boreholes were placed around the containment area to determine the extent of contamination. The visual oil contamination in the subsurface extends approximately 225 feet downgradient and is approximately 150 feet wide at the widest point. In April 2012, an additional 30,000 gallons of oil was released from a leak in a fuel line in the same area resulting in free product on the ground water.
Dave Johnston Pond 4A & 4B	75 435	19 666	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Eugene MGP (50% PCRP)	41 918	10 928	A manufactured gas plant (MGP) was formerly operated on the approximately 1.5-acre Site now owned by Eugene Water and Electric Board (EWEB). Most of the former MGP operational area is located on property now owned by EWEB, however, some MGP operations also occurred to the east and south on properties owned by University of Oregon and the City of Eugene, respectively. The MGP was constructed in 1906 as a coal carbonization process facility and operated in that mode from 1907 until approximately 1910, when it was converted to a carbureted water-gas plant. The plant was expanded and converted to the water-gas operation in 1910–11. The plant was used to manufacture gas until approximately 1950, when it was converted to a propane-air gas operation. Later the plant was converted to the storage and distribution of propane. By approximately 1972, all remaining aboveground structures (except the main brick building) had been removed from the Site. EWEB purchased the Site in 1976. Investigations of soil, groundwater, and surface water began around 1995, following the discovery of contaminants during sampling by University of Oregon on its property and the review of other historical documentation. The nature and extent of soil and groundwater impact has been documented in Remedial Investigation, Risk Assessment, Ecological Risk Assessment and Feasibility Study (RI/FS) reports completed for the site under Oregon Department of Environmental Quality (DEQ) intergovernmental agreement WMCVC-WR-98-13, dated November 25, 1998. The investigation and remedial activities at the site are managed by EWEB but responsibilities and costs are shared between EWEB, Cascade Natural Gas, and PacifiCorp.
Everett MGP (2/3 PCRP)	1,594	416	The former Everett Manufactured Gas Plant (MGP) operated from approximately 1904 until approximately 1941. The plant was operated by the Everett Gas Company until approximately 1910, and by Puget Sound Gas Company until approximately 1927. The site was then transferred to Mountain States Power, a Pacific Power and Light Company predecessor. In approximately 1927, the site was sold to Washington Gas and Electric Company, which owned and operated the site until approximately 1941. In 1941, the plant was decommissioned and replaced with a butane air facility. It continued to operate in this way until 1956 when it was placed on standby. The site is currently utilized for service operations by Puget Sound Energy. Residual contamination from MGP operations have been detected in the soil and groundwater at the site.
Freeport Substation	10,054	2,661	The Freeport substation is the site of the historic Freeport Substation that was decommissioned over 30 years ago. As part of a possible sale of the property, the site soil was sampled. PCBs were found on the property. This project entails the complete characterization of the PCB impacts, removal of PCB contaminated soil, verification sampling, coordination and reporting to regulatory agencies and backfilling.
Geneva Rock Bldg. - Hunter Plant	4,367	1,139	During the construction of the Hunter plant in the 1970s, a concrete batch plant was constructed on PacifiCorp property. A small building associated with the batch plant remains on PacifiCorp property but is located outside the fenced plant area. The roof of the building is about three feet above grade. A recent inspection of the building found the building two thirds full of an oil/water mixture. A small tank is also in the building. The first task will be to remove the water and oil from the building to make it safe to enter. Then the building will be removed. Following building removal, soil and ground water sampling contamination will be addressed.
Hunter Fuel Oil Spills	15,946	4,157	The Hunter Plant is a steam electric plant which has two coal-fired boilers located in Castle Valley, Utah. The boiler operations are augmented with fuel oil to stabilize the coal during ignition. The plant has experienced several fuel oil releases over the years, mainly from the buried fuel oil lines. Ground water is at approximately 20 feet. Investigations have determined that the plant drains under the pond have been impacted with oil. In addition, the soil beneath the oil storage tanks is impacted.
Huntington Ash Landfill	21,905	5,711	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Huntington Plant Ash Landfill	82 520	21 513	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Idaho Falls Pole Yard	219,827	58,194	The Idaho Falls Pole Yard was a pole treating facility which operated from early 1930's until 1983 when a creosote leak was found in underground piping leading to the treatment vat. Site characterization determined that creosote had entered the groundwater. An active pump and treat system operated from the late 1980's through October 2019 when groundwater levels were deemed acceptable.
Jordan Plant Substation	16 413	4 345	PacifiCorp owned and operated an electric generating plant at the site from 1911 to about 1976. The plant was demolished in the mid 1980s. During the construction of a substation on the property in the late mid 1990s, DNAPL was found in one of the excavations for a utility pole. The site has been characterized. DNAPL extends over an area approximately 30 feet wide and 70 feet long. Part of the DNAPL is under the Jordan River. The Utah DEQ determined that all active remedial efforts were infeasible. The site continues under a Site Management Plan which requires quarterly inspections and periodic groundwater sampling.
Klamath Falls	5 460	1 424	Estimate here is based on remediation costs provided by the KRRC after evaluating the results of the Phase 1 Environmental Site Assessments that were prepared for the Lower Klamath Project. These costs have not been informed by implementation of the SIWPs. The most likely estimate provided below is a blend of the low, mid, and high costs provided for each REC by the KRRC that is based on PacifiCorp's understanding of each site. The maximum cost below is the maximum cost for each REC as provided by the KRRC.
Little Mountain Gas Plant	105,602	27,531	The Little Mountain Plant produces steam for the Great Salt Lake Minerals (GSL) facility. The contract with GSL is expiring and is not being renewed. The plant will be retired and physically removed. The plant has had several oil releases over its operating life. These areas will need to be remediated. Management has decided for liability reasons to clean the site up to residential levels.
Montague Ranch (CA)	14,224	3,766	The operation of an underground storage tank at the site resulted in a release of gasoline to soil and groundwater. A network of 14 shallow and deep groundwater monitoring well were installed at the site between 1997 and 2007. The extent of contamination has been adequately defined. Elevated concentrations of benzene, toluene, ethyl benzene, and xylenes (BTEX) were detected in the source area. PacifiCorp conducted a feasibility study; the selected remedial alternative for the source area was excavation and offsite disposal of soil from the source area of contamination as well as the placement of a chemical oxidant in the excavation to further promote degradation of residual contaminants in the groundwater. A Corrective Action Plan was approved by the California Regional Water Quality Control Board (RWQCB) and implemented in October and November 2010.
Naughton FGD Pond Closure	29,536	7,700	The purpose of this project is to close FGD Pond #1 at the Naughton Plant when it is no longer needed. The pond was originally slated for closure in 2002 but the plant decided not to close the pond but increased its capacity instead and continues to operate it. It is project will also be used to install and maintain a pump back system to remediate a leak in the #2 FGD Pond. The construction work for the pump back system was completed in November 2006. The system will also require ongoing monitoring and maintenance.
Naughton Oil Spill	2,570	670	In the fall of 2016 during a geotechnical study, petroleum contaminated soil was discovered in one of the boreholes. Analysis revealed gas/diesel contamination. The release was report to Wyoming DEQ. The initial phase is to characterize the extent of the contamination.
Naughton Plant - FGD Pond 1	39,370	10,264	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Naughton Plant - FGD Pond 2	68 769	17 928	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
Naughton South Ash Pond	6 694	1 745	EPA CCR regulation's require groundwater sampling at each CCR unit. If groundwater impacts are found, corrective action is required. The required initial groundwater sampling was completed in 2018 and impacts were found and corrective action was initiated.
NTO Parking Lot-Asbestos 2018	21,774	5,917	Remediation of asbestos discovered in the asphalt and dirt that was hauled from the parking lot at NTO.
Ogden MGP	532 769	138 895	The former Ogden manufactured gas plant operated from 1892 to 1930. It was owned and operated by Utah Power & Light Company predecessor companies from 1892 to 1928. After 1928, the Ogden MGP was owned and operated by Utah Gas & Coke a predecessor to Mountain Fuel Supply. The current owner is Ogden Auto Body - an auto repair facility.
Olympia MGP	1,416	369	Remaining portion of the Olympia manufactured gas plant cleanup

Pendleton Service Center (OR)	548	145	As part of the development of the Spill Prevention, Control and Countermeasures plan for the site, it was noted that the discharge from an oil/water separator was directed to an offsite ditch for the collection of storm water. Due to the presence of potential contaminants in the discharge from the oil/water separator, soil samples were collected in July 2014 and analyzed for oil and polychlorinated biphenyls (PCBs). No PCBs were detected in any of the soil samples; levels of oil were detected below action levels. No further investigation activities are warranted at this site.
Portland Harbor Service Center and Insurance	567,194	150,151	PacifiCorp has been identified as a potentially responsible party at the Portland Harbor Superfund Site related to sediment impacts adjacent to the east bank of the Willamette River between river miles 10.9 and 11.6. The area is located just south of the Fremont Bridge along North River Street. PacifiCorp owns and formerly owned some parcels of property located within this area including the Albina Substation and the Knott Substation. PacifiCorp entered into a Voluntary Agreement with the Oregon Department of Environmental Quality on January 14, 2009 to evaluate its upland properties and conduct source control. PacifiCorp, along with 5 other parties, also entered into an Administrative Settlement Agreement and Order on Consent with the Environmental Protection Agency to prepare a remedial design to address sediment containing elevated levels of polychlorinated biphenyls.
Powerdale Hydro Plant	13	4	Remaining portion of the Powerdale hydro plant environmental project
Ririe Substation	1 297	343	The Ririe substation is being decommissioned. The sub has a transformer >50 ppm PCB that has leaked. Regulations require the characterization and remediation of the soils.
Silver Bell Mine Environmental	1,054,006	274,783	In the mid 1990's the tailing impoundment began to deteriorate. In order to limit liability, PacifiCorp decided to take action to stabilize the tailings. EPA and the State of Colorado were approached about the site and it was decided to do the work under the Colorado's Voluntary Cleanup Program. In the Summer of 1999, the tailings were consolidated into one area on the property. In the summer of 2000, the tailings were capped with a soil and rock cover and vegetation was planted. Maintenance and monitoring continues at the site.
SPCC - Spill Clean Up	1 512 873	400 497	This project includes the development and maintenance of Spill Prevention Control and Countermeasures (SPCC) for all substations as well as costs associated with any spill response requests.
Sunnyside Service Center (WA)	108	29	This project includes the development and maintenance of Spill Prevention Control and Countermeasures (SPCC) for all substations as well as costs associated with any spill response requests.
Tacoma A St. (25% PCRP)	4,407	1,149	The Tacoma former manufactured gas plant (MGP) site was contaminated historically by several sources, including a former coal gasification plant and a former three-tank storage facility, an orphan chemical plant, and storm drains. PRPs at the site include PacifiCorp, Puget Sound Energy, Washington Department of Transportation and the City of Tacoma. There is an Agreed Order in place with the Washington State Department of Ecology.
Utah Metals Cleanup	43,159	11,425	The Utah Metals facility is a metals salvage yard. From approximately 1956 through 1984, Utah Power sent transformers to the site for decommissioning. During the decommissioning of the transformers, PCB oil was mishandled and contaminated the concrete and soils at the Utah Metals facility.
Wyodak Fuel Oil Spill	13,450	3,561	The plant had two separate leaks from the fuel oil lines. One impacted just soil and the other resulted in free product in the subsurface. The contaminated soil has been closed. The free product was bailed from a series of wells by plant personnel. The state was notified responded in Jan 2010 and required semi-annual sampling of 15 wells until ground water clean up levels are achieved.
	5,917,169	**1,552,529**	

AWEC Data Request 016

Reference PacifiCorp's supplemental response to OPUC 69, Supplemental Attachment 1, cell "D9": Please provide an updated version of the attachment provided in Rocky Mountain Power's response to PIIC Production Request 57 in Idaho Docket PAC-E-21-07 supporting the value calculated in the referenced cell.

Response to AWEC Data Request 016

The Company assumes that the reference to "supplemental response to OPUC 69" is intended to be a reference to the Company's 1st Revised response to Standard Data Request – OPUC 069, specifically Confidential Attachment OPUC 069-1 1st REVISED, file "OPUC 069-1 CONF". Based on the foregoing assumptions, the Company responds as follows:

Please refer to Confidential Attachment AWEC 016 which provides an updated version of the Company's confidential attachment to PIIC Data Request 57 in PacifiCorp's Idaho general rate case (GRC), Case PAC-E-21-07.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

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AWEC Data Request 017

Reference Cheung work paper "8.2 - Trapper Mine Rate Base" Tab 8.2: Please explain why the Final Reclamation liability is stated on a 12-month average, while the other plant balances are stated on an end-of-period basis.

Response to AWEC Data Request 017

The Final Reclamation liability is stated on a 12-month average because this balance is recorded in FERC Account 253.3, which is part of cash working capital (CWC). All CWC balances are reported on a 12-month average basis, consistent with a long history of prior general rate cases (GRC), including the Company's most recent GRC, Docket UE-374. The other plant balances are stated on an end-of-period basis in a manner consistent with the approved rate base methodology for plant balances in the Company's most recent approved GRC, Docket UE-374, in Order No. 20-473.

AWEC Data Request 018

Reference Cheung work paper “8.2 - Trapper Mine Rate Base” Tab 8.2: Please explain why the Final Reclamation liability adjustment only reflects the difference between the 12-month average ending June 2021 and the 12-month average ending December 2022, rather than the entire Final Reclamation liability balance.

Response to AWEC Data Request 018

The 12-months ended June 2021 average Final Reclamation liability balance is included in rate base as part of base period results of operations (ROO) that served as the starting point in the calculation of revenue requirement in this general rate case (GRC). Therefore, the incremental adjustment to Final Reclamation liability required to properly reflect the test period average Final Reclamation liability only needs to reflect the difference between the forecasted test period average balance, and the base period average balance for 12-months ended June 2021.

AWEC Data Request 019

Reference Cheung work paper "8.2 - Trapper Mine Rate Base" Tab 8.2: Is the final reclamation liability balance included in the results of operations for the 12 months ending June 2021? If yes, please identify the FERC account where the liability balance is included and provide transactional data supporting the balance.

Response to AWEC Data Request 019

Yes, the Final Reclamation liability balance is included in the results of operations (ROO) for the 12 months ended June 2021 in FERC Account 253.3. Please refer to Attachment AWEC 019 which provides the transactional data supporting the balance.

Attachment AWEC 019

Calendar Year	Posting Period	Document Number	Document Type	Document Date	In Transaction Currency	FERC Account	FERC Location
2020	7	138695926	SA	7/24/2020	(22,995)	2533000	906
2020	7	138695926	SA	7/24/2020	22,419	2533000	906
2020	7	138750712	SA	7/31/2020	(21,743)	2533000	906
2020	8	138779656	SA	8/18/2020	(21,743)	2533000	906
2020	8	138779656	SA	8/18/2020	21,743	2533000	906
2020	8	138846851	SA	8/31/2020	(11,903)	2533000	906
2020	9	138880289	SA	9/21/2020	(12,036)	2533000	906
2020	9	138880289	SA	9/21/2020	11,903	2533000	906
2020	9	138945118	SA	9/30/2020	(17,863)	2533000	906
2020	10	139228385	SA	10/20/2020	(17,863)	2533000	906
2020	10	139228385	SA	10/20/2020	17,863	2533000	906
2020	10	139298829	SA	10/31/2020	(18,593)	2533000	906
2020	11	139336853	SA	11/23/2020	(18,593)	2533000	906
2020	11	139336853	SA	11/23/2020	18,593	2533000	906
2020	11	139391435	SA	11/30/2020	(17,161)	2533000	906
2020	12	139418385	SA	12/16/2020	(17,161)	2533000	906
2020	12	139418385	SA	12/16/2020	17,161	2533000	906
2020	12	139494526	SA	12/31/2020	(21,593)	2533000	906
2021	1	139787900	SA	1/26/2021	(21,593)	2533000	906
2021	1	139787900	SA	1/26/2021	21,593	2533000	906
2021	1	139840134	SA	1/31/2021	(178,003)	2533000	906
2021	2	139880058	SA	2/23/2021	(119,711)	2533000	906
2021	2	139880058	SA	2/23/2021	178,003	2533000	906
2021	2	139930945	SA	2/28/2021	(117,829)	2533000	906
2021	3	139956477	SA	3/18/2021	(117,829)	2533000	906
2021	3	139956477	SA	3/18/2021	117,829	2533000	906
2021	3	140025693	SA	3/31/2021	(135,520)	2533000	906
2021	4	140316687	SA	4/21/2021	(162,885)	2533000	906
2021	4	140316687	SA	4/21/2021	135,520	2533000	906
2021	4	140380195	SA	4/30/2021	(58,302)	2533000	906
2021	5	140412396	SA	5/20/2021	(79,389)	2533000	906
2021	5	140412396	SA	5/20/2021	58,302	2533000	906
2021	5	140475659	SA	5/31/2021	(109,127)	2533000	906
2021	6	140507014	SA	6/17/2021	(109,154)	2533000	906
2021	6	140507014	SA	6/17/2021	109,127	2533000	906
2021	6	140578647	SA	6/30/2021	(122,436)	2533000	906

Attachment AWEC 019

FERC Secondary	Text	Balance	
		(6,851,897)	
289517	Craig - Trapper Reclamation	(6,874,893)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,852,474)	
289517	Craig Preliminary Trapper Reclamation	(6,874,217)	
289517	Craig - Trapper Reclamation	(6,895,961)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,874,217)	
289517	Craig Preliminary Trapper Reclamation	(6,886,120)	
289517	Craig - Trapper Reclamation	(6,898,156)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,886,253)	
289517	Craig Preliminary Trapper Reclamation	(6,904,116)	
289517	Craig - Trapper Reclamation	(6,921,979)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,904,116)	
289517	Craig Preliminary Trapper Reclamation	(6,922,709)	
289517	Craig - Trapper Reclamation	(6,941,303)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,922,709)	
289517	Craig Preliminary Trapper Reclamation	(6,939,870)	
289517	Craig - Trapper Reclamation	(6,957,031)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,939,870)	
289517	Craig Preliminary Trapper Reclamation	(6,961,463)	
289517	Craig - Trapper Reclamation	(6,983,056)	
289517	CRAIG Rev Est - Trapper Reclamation	(6,961,463)	
289517	Craig Preliminary Trapper Reclamation	(7,139,466)	
289517	Craig - Trapper Reclamation	(7,259,177)	
289517	CRAIG Rev Est - Trapper Reclamation	(7,081,174)	
289517	Craig Preliminary Trapper Reclamation	(7,199,003)	
289517	Craig - Trapper Reclamation	(7,316,832)	
289517	CRAIG Rev Est - Trapper Reclamation	(7,199,003)	
289517	Craig Preliminary Trapper Reclamation	(7,334,523)	
289517	Craig - Trapper Reclamation	(7,497,408)	
289517	CRAIG Rev Est - Trapper Reclamation	(7,361,888)	
289517	Craig Preliminary Trapper Reclamation	(7,420,190)	
289517	Craig - Trapper Reclamation	(7,499,578)	
289517	CRAIG Rev Est - Trapper Reclamation	(7,441,276)	
289517	Craig Preliminary Trapper Reclamation	(7,550,403)	
289517	Craig - Trapper Reclamation	(7,659,557)	
289517	CRAIG Rev Est - Trapper Reclamation	(7,550,430)	
289517	Craig Preliminary Trapper Reclamation	(7,672,867)	
	12-Month Avgerage	**(7,150,412)**	*Ref Cheung, B-Tabs Workpaper.*

AWEC Data Request 021

Reference Cheung work paper "8.2 - Trapper Mine Rate Base" Tab 8.2.1: Are the inventory amounts on Excel Row 18 fuel stock? If the balances include items other than fuel stock, please provide detail of each inventory item included in the balances.

Response to AWEC Data Request 021

The inventory line contains both coal inventory and materials and supplies (M&S) inventory. The forecasted inventory balance for 2022 is based on historical inventory balances and assumes a similar balance consistent with continued operations at the plant. A detail of forecasted inventory values was not provided to PacifiCorp.

AWEC Data Request 023

Please provide the balance sheet, income statement, and statement of cashflows from the Trapper Mine for calendar year 2021, including notes accompanying the financial statements.

Response to AWEC Data Request 023

Please refer to Confidential Attachment AWEC 023.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

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AWEC Data Request 030

Reference Cheung Work paper "B19 - Deferred Income Tax Balance", Excel Row 67: Please provide a description of the book tax difference item "DTA 705.400 Reg Lia - OR Inj & Dam Reser," including an explanation of the timing of when the expense is incurred and when the amounts are deducted for tax purposes. Please also explain how this $3,053,000 Oregon-allocated item is considered in revenue requirement.

Response to AWEC Data Request 030

This deferred tax asset represents the deferred tax impact related to the regulatory liability for Oregon Injuries and Damages Reserve. Pursuant to Docket UE 217, Order No. 10-473, the Company established monthly accruals and related reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution property losses, and third-party liability insurance. The Company's self-insurance accruals began after March 31, 2011 along with the establishment of the deferred tax asset on the accruals.

Internal Revenue Code (IRC) §461 provides that a contingent liability or loss reserve may not be deducted for income tax purposes until economic performance has occurred. Economic performance typically occurs when an amount is paid out to a third-party vendor.

The deferred tax asset is recorded in FERC Account 190 and is a rate base increase for revenue requirement purposes.

AWEC Data Request 034

Reference Cheung Work paper "B19 - Deferred Income Tax Balance," Excel Row 99: Please provide the NOL Carryforward balances by state for each tax year 2017 through 2021. Use PacifiCorp's tax provision for 2021 if the tax returns have not yet been completed.

Response to AWEC Data Request 034

Please refer to Attachment AWEC 034.

Attachment AWEC 034

Net Operation Loss Carryforward Balances							
Jurisdiction	**California**	**Idaho**	**Montana**	**Oregon**	**Utah**	**Colorado**	**Total**
2017	549,579	3,054,530	186,727	30,682,550	37,648,894	667,424	**72,789,704**
2018	287,455	2,730,690	8,204	28,649,718	34,827,689	665,195	**67,168,951**
2019	287,455	2,730,690	-	28,649,718	34,827,689	646,440	**67,141,992**
2020	287,455	2,730,690	-	28,649,718	34,827,689	648,882	**67,144,434**
2021	287,455	2,563,103	-	28,649,718	34,827,689	648,882	**66,976,847**

AWEC Data Request 045

Reference Cheung work paper "B4 - Amortization Expense," Excel Row 84: Please provide a detailed description of the amount "Amortz Reg A-Unrcvrd Plt/Decom Csts-OR" and work papers supporting the calculation of the amortization expense.

Response to AWEC Data Request 045

Please refer to Attachment AWEC 045 which provides the item detail of what is included in the "Amortz Reg A-Unrcvrd Plt/Decom Csts-OR" amortization expense.

The $89,000 of Carbon Amortization was reflected as the Base Period amortization expense the Carbon Plant Closure Adjustment that is included in this general rate case (GRC). The pro-forma adjustment to Carbon Plant Closure amortization made in this GRC is net of this Base Period amount. Please refer to the non-confidential work papers supporting the direct testimony of Company witness, Sherona L. Cheung, specifically "8 – Rate Base", file "8.16 – Carbon Plant Closure.xlsx".

The $967,000 amortization related to the Meter Replacement should have been excluded as this amount is being recovered through Schedule 194 (Replaced Meter Deferred Amounts Adjustment). The Company will remove this amortization in its Reply Testimony filing.

AWEC Data Request 047

Reference Cheung work paper "B8 – EPIS" Excel Row 68: Please provide an explanation for how the item titled "OR VHF (VPC) SPECTRUM" in the amount of $4,071,000 benefits Oregon customers.

Response to AWEC Data Request 047

The VHF (VPC) SPECTRUM item was part of the Old Mobile Radio project where the Company purchased exclusive rights to several channel frequencies for the Company's microwave operations. These rights go to perpetuity and are not being amortized. There has been no additions to the balance since the year 2016, so the entirety of this balance was included as part of rate base approved in the Company's last general rate case, Docket No. UE 374.

AWEC Data Request 052

Reference Cheung work paper “8.15 - Miscellaneous Rate Base:” Please provide detailed work papers used to forecast fuel stock for each coal plant in the test period

Response to AWEC Data Request 052

Please refer to Confidential Attachment AWEC 052 which provides the forecasted fuel stock.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

[redacted]

AWEC Data Request 053

Reference Cheung work paper "8.15 - Miscellaneous Rate Base:" Please provide an explanation for the fuel stock associated with the line item Rock Garden and describe how that fuel stock benefits Oregon customers.

Response to AWEC Data Request 053

The fuel inventory held at the Rock Garden represents a "safety" coal reserve stockpile. This safety pile exists to mitigate ongoing risks that are inherent in underground mining operations used by the existing coal mining companies in Utah that provide coal to both the Hunter and Huntington power plants. In addition to the underground mining risks, there are financial risks associated with the coal companies as well. In recent years a significant number of Utah coal companies have filed for bankruptcy. The Rock Garden "safety" pile provides additional security of supply against some of these unknown risks for all customers.

AWEC Data Request 056

Please identify each pit at the Trapper Mine and the initial date that mining began for each pit.

Response to AWEC Data Request 056

Trapper Mine does not maintain a report with this information.

AWEC Data Request 063

Please identify the amount of Utah DSM load and/or demand considered as an offset to Utah's allocation factors.

Response to AWEC Data Request 063

Please refer to the table below which provides the amounts of Utah demand-side management (DSM) demand in Mega-watts (MW) considered as a reduction to Utah's allocation factors for the forecast test period in this general rate case (GRC):

	UT Demand Side Management (MW)
Month	
Jan-23	120
Feb-23	120
Mar-23	120
Apr-23	120
May-23	197
Jun-23	251
Jul-23	258
Aug-23	254
Sep-23	231
Oct-23	120
Nov-23	120
Dec-23	120
	2,029

AWEC Data Request 064

Please provide a description of each Utah DSM program with load and/or demand considered as an offset to Utah's allocation factors and explain why the amount offsets Utah's load and/or demand.

Response to AWEC Data Request 064

Please refer to the following for description of each Utah demand-side management (DSM) program with load considered a reduction to Utah's jurisdictional loads for allocation purposes:

- Utah Cool Keeper Program – The Cool Keeper program is an air conditioner direct load management program targeting residential and commercial customers who cool their dwellings with electric central air conditioners. The program is called upon curtailment under varying circumstances.
- Utah Irrigation Load Control Program – The irrigation load control program is offered to irrigation customers receiving electric service on Schedule 10, Irrigation and Soil Drainage Pumping Power Service. Participants enroll in the program with a third-party administrator and allow the curtailment of their electricity usage in exchange for an incentive. Customer incentives are based on the site's average available load during load control program hours, adjusted by opt outs or non-participation.
- Utah Wattsmart Batteries – The Wattsmart Batteries program promotes and incentivizes the installation of individual batteries for system-wide integration and use for overall grid management. Leveraging batteries has created opportunity in areas including Utility Grid Management, Load Shaping, Utility Integration of Behind-the-Meter Batteries, and Utilization of the Distributed Battery Grid Management Solution platform.
- Utah Commercial and Industrial Thermostat – Commercial and Industrial demand response program currently being filed in Utah.

The treatment of DSM program loads for allocation purposes in this general rate case (GRC) is consistent with the approved Execution Version of 2020 Protocol in Docket UM-1050, specifically in Section 3.1.2.1 of Appendix B, which states as follows:

> "Demand-Side Management ("DSM") Programs: Costs associated with DSM Programs, including Class 1 DSM Programs, will be allocated on a situs basis to the State in which the investment is made. ***Benefits from these programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors*" *(emphasis added).***

AWEC Data Request 066

Please provide the hourly curtailments associated with the Utah Cool Keeper programs loads over the period January 1, 2017, through December 31, 2021.

Response to AWEC Data Request 066

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Forecasted loads in this case were not derived based on historical information, but rather forecasted information for the test period. Without waiving the foregoing objection, PacifiCorp responds as follows:

Please refer to Attachment AWEC 066. Note: this information is available in the Company's Energy Efficiency and Peak Reduction Annual Reports, which are filed with the Public Service Commission of Utah (UPSC) and also available on the Company's website at the following:

https://www.pacificorp.com/environment/demand-side-management.html

Table 11
Cool Keeper Load Control Events

Date	Event	Event Times	Estimated Load Reduction - Utah at Gen (MW)
June 21, 2017	1	7:00PM – 7:30PM	106
August 29, 2017	2	4:45PM – 6:00PM	112

Table 11
Cool Keeper Load Control Events

Date	Event	Event Times	Estimated Load Reduction - Utah at Gen (MW)
June 4, 2018	1	5:33PM-5:45PM	144
June 6, 2018	2	2:24PM-2:29PM	71
June 27, 2018	3	3:58PM-4:28PM	142
June 27, 2018	4	4:47PM-4:53PM	66
June 28, 2018	5	2:53PM- 3:29PM	159
July 18, 2018	6	5:09PM-5:14PM	192
July 18, 2018	7	6:30PM-6:35PM	201

UE 399 / PacifiCorp
AWEC Data Request 066 – Attachment AWEC 066

Table 10
Cool Keeper Load Control Events

Date	Event	Event Times (MST)	Utah Reductions (MW)
5/16/2019	1	15:58 - 16:10	21
6/27/2019	2	13:20 - 13:25	36
7/26/2019	3	1:12 - 1:17	62
8/1/2019	4	13:51 - 13:56	103
8/3/2019	5	14:41 - 14:46	138
8/5/2019	6	11:01 - 11:06	101
8/7/2019	7	9:36 - 9:42	67
8/16/2019	8	9:21 - 9:26	39
8/18/2019	9	19:38 - 20:00	202
8/21/2019	10	2:41 - 2:50	43
8/23/2019	11	11:43 - 11:48	48
9/2/2019	12	3:29 - 3:34	45
9/3/2019	13	13:15 - 13:20	74
9/4/2019	14	17:22 - 17:45	191
9/5/2019	15	15:35 - 16:16	159
9/10/2019	16	22:22 - 22:27	30
9/11/2019	17	21:52 - 21:57	17
9/19/2019	18	3:01 - 3:06	16
11/4/2019	19	5:32 - 5:37	0

UE 399 / PacifiCorp
AWEC Data Request 066 – Attachment AWEC 066

Table 11: Cool Keeper Load Control Events

Date	Event Times (MST)	Utah Reductions (MW)
4/30/2020	13:46 MDT – 13:50 MDT	30
5/1/2020	14:00 MDT – 14:29 MDT	14
5/5/2020	17:52 MDT – 17:57 MDT	29
5/8/2020	7:11 MDT – 7:16 MDT	N/A[12]
5/19/2020	14:30 MDT - 14:35 MDT	46
6/5/2020	15:40 MDT - 15:43 MDT	112
6/7/2020	17:34 MDT - 17:38 MDT	11
6/9/2020	12:11 MDT - 12:16 MDT	5
6/18/2020	16:21 MDT - 16:26 MDT	24
7/7/2020	12:41 MDT - 12:46 MDT	166
7/12/2020	21:30 MDT - 22:02 MDT	200
7/17/2020	14:46 MDT - 14:51 MDT	133
7/19/2020	12:54 MDT - 1:02 MDT	200
7/25/2020	1:29 MDT - 1:34 MDT	65
7/26/2020	12:27 MDT - 12:32 MDT	120
7/28/2020	10:26 MDT - 10:31 MDT	69
7/29/2020	10:44 MDT - 11:12 MDT	53
7/30/2020	18:47 MDT - 18:52 MDT	222
8/3/2020	15:08 MDT - 15:13 MDT	186
8/9/2020	22:11 MDT - 22:15 MDT	126
8/19/2020	15:30 MDT - 15:31 MDT	193
8/21/2020	16:54 MDT - 16:59 MDT	184
8/24/2020	9:36 MDT - 10:00 MDT	53
9/3/2020	21:16 MDT- 21:20 MDT	107
9/5/2020	16:02 MDT 16:07 MDT	175
9/7/2020	16:29 MDT - 16:34 MDT	147
9/8/2020	2:52 MDT - 2:57 MDT	17

Table 11: Cool Keeper Load Control Events

Date	Event Times (MST)	Utah Reductions (MW)
5/7/21	13:25 –13:30 MDT	16
5/19/21	16:14 - 16:19 MDT	9
6/14/21	18:34 - 18:45 MDT	211
7/13/21	10:04 - 10:09 MDT	82
7/17/21	12:25 - 12:44 MDT	120
7/18/21	17:17 - 17:22 MDT	220
7/25/21	19:49 - 19:54 MDT	188
7/27/21	12:24 - 13:09 MDT	103
8/2/21	13:56 - 14:01 MDT	40
8/8/21	18:39 - 18:42 MDT	174
8/9/21	16:05 - 16:21 MDT	135
8/10/21	3:04 - 3:29 MDT	30
8/12/21	16:21 - 16:24 MDT	191
8/13/21	17:47 - 17:52 MDT	215
8/20/21	2:37 - 2:42 MDT	6
8/21/21	00:24 - 00:55 MDT	21
8/24/21	14:45 - 14:50 MDT	101
8/25/21	15:15 - 15:20 MDT	123
8/25/21	15:29 - 15:34 MDT	0
8/28/21	18:03 - 18:14 MDT	117
9/4/21	10:31 - 10:53 MDT	18
9/5/21	15:46 - 16:01 MDT	96
9/13/21	13:18 - 13:23 MDT	79
9/21/21	14:58 - 15:22 MDT	13
9/28/21	15:18 - 15:23 MDT	22

AWEC Data Request 068

Please identify the total amount of load enrolled in the Utah Cool Keeper program as of December 31, 2021.

Response to AWEC Data Request 068

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Forecasted loads in this case were not derived based on historical information, but rather forecasted information for the test period. Without waiving the foregoing objection, PacifiCorp responds as follows:

Please refer to the table below which provides Utah Cool Keeper program details as of December 31, 2021. Note: this information is available in the Company's Energy Efficiency and Peak Reduction Annual Reports, which are filed with the Public Service Commission of Utah (UPSC) and also available on the Company's website at the following:

https://www.pacificorp.com/environment/demand-side-management.html

Table 12: Program Performance for Cool Keeper

Maximum Potential MW (at Site)	**254**
Maximum Potential MW (at Gen)	270
Average Realized Load MW (at Site)	93
Maximum Realized MW (at Site)	220
Total Participating Customers	93,904

AWEC Data Request 069

Please identify the total amount of load enrolled in any Utah DSM program, other than the Utah Cool Keeper program loads, which is included as an offset to Utah's allocation factors

Response to AWEC Data Request 069

PacifiCorp objects to this request as outside the scope of this proceeding, and not reasonably calculated to lead to the discovery of admissible evidence. Forecasted loads in this case were not derived based on historical information, but rather forecasted information for the test period. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company assumes this request is also seeking total amount of load enrolled as of December 31, 2021, consistent with AWEC Data Request 068. Subject to the foregoing assumption, the Company responses as follows:

Please refer to the table below which provides Utah Irrigation Load Control Program details as of December 31, 2021. Note: this information is available in the Company's Energy Efficiency and Peak Reduction Annual Reports, which are filed with the Public Service Commission of Utah (UPSC) and also available on the Company's website at the following:

https://www.pacificorp.com/environment/demand-side-management.html

Table 10: Irrigation Load Control Program Performance

Maximum Potential MW (at Site)	**13**
Maximum Potential MW (at Gen)	14
Average Realized load MW (at Site)	3
Maximum Realized load MW (at Site)	4
Total Customer Participation	31
Total Sites	131

AWEC Data Request 070

Please provide the load forecast work papers used in this proceeding and identify the date that it was developed.

Response to AWEC Data Request 070

Please refer to the non-confidential work papers supporting the direct testimony of Company witness, Kenneth Lee Elder, Jr, specifically file "Load Forecast Workpaper". The work papers were developed in February 2022.

AWEC Data Request 073

Please identify the specific date that each Energy Vision 2020 project, including Pryor Mountain, went into service.

Response to AWEC Data Request 073

Please refer to the information below which provides the dates when the following PacifiCorp owned wind generation projects were fully placed in service (based on the respective dates that the last turbines came online):

Cedar Springs Wind II (Energy Vision 2020 (EV 2020 project) – December 8, 2020.
Ekola Flats Wind (EV 2020 project) – December 30, 2020.
Pryor Mountain Wind – March 31, 2021.
TB Flats Wind I/II (EV 2020 project) – July 26, 2021.

Please refer to the information below which provides the dates when the following PacifiCorp transmission projects were placed in service:

Aeolus to Bridger/Anticline Transmission Line (EV 2020 project) – November 4. 2020
230 kilovolt (kV) Network Upgrades (EV 2020 project) – November 1. 2020

AWEC Data Request 074

Please calculate the revenue requirement impact associated with the delayed in-service date for each of the Energy Vision 2020 Projects, including Pryor Mountain, that were not in service by the rate effective date of PacifiCorp's last general rate case.

Response to AWEC Data Request 074

Energy Vision (EV) 2020 projects that were not yet placed in-service, or portions not placed in-service were removed from rates that became effective January 1, 2021 from the Company's last general rate case (GRC). Upon completion of each project, the Company filed compliance filings for subsequent rate adjustments to include each project's costs into Oregon rates. Specifically, the Ekola Flats Wind project was included in rates through the Company's compliance filing for Docket UE-374, filed January 7, 2021; and the Pryor Mountain Wind project was added to rates through a compliance filing to Docket UE-374, filed April 5, 2021. As such, there is no revenue requirement impact to Oregon customers associated with the delayed in-service date for EV 2020 projects, including the Pryor Mountain Wind project.

To date, all EV 2020 projects have been included in rates with exception of a portion of the TB Flats Wind project that was not completed until July 2021. The revenue requirement on the portion of the TB Flats Wind project not in rates has been deferred, and the Company has requested in the current GRC to begin amortization of the deferred revenue requirement over three years. Please refer to Exhibit PAC 1002/Cheung/274-283. Please also refer to non-confidential work papers supporting the direct testimony of Company witness, Sherona L. Cheung, specifically "8 – Rate Base", file "8.14 – Wind Projects Deferrals Amortization.xlsx".

Page 40 of Exhibit AWEC/103 includes Protected Information Subject to General Protective Order No. 22-044 and has been redacted in its entirety.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/104

OREGON TAX BENEFIT OF BHE INTEREST DEDUCTION

Tax Benefit of BHE Holding Company Debt Attributable to PacifiCorp

Maturity	Principal ($000)	Interest Rate	Expense
2021	-	2.38%	-
2023	398,000	2.80%	11,144
2023	499,000	3.75%	18,713
2025	398,000	3.50%	13,930
2025	1,246,000	4.05%	50,463
2028	594,000	3.25%	19,305
2028	260,000	8.48%	22,048
2030	1,096,000	3.70%	40,552
2031	497,000	1.65%	8,201
2036	1,661,000	6.13%	101,736
2037	548,000	5.95%	32,606
2037	223,000	6.50%	14,495
2043	740,000	5.15%	38,110
2045	738,000	4.50%	33,210
2048	738,000	3.80%	28,044
2049	990,000	4.45%	44,055
2050	889,000	4.25%	37,783
2051	1,488,000	2.85%	42,408
Total	13,003,000	4.28%	556,802
BHE Total Capitalization	132,065,000		132,065,000
PacifiCorp Capitalization	26,456,000		26,456,000
%	20.03%		20.03%
PacifiCorp Share	2,604,834		111,542
SO Factor	27.17%		27.17%
Oregon Deduction	707,813.61		30,309.30
		Tax Affected at 24.6%	**7,456.088**

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EXHIBIT AWEC/105

FLY ASH DEFERRAL CALCULATION

UM 2201 Fly Ash Deferral Calculation

In Rates	92,294	7.14% RoR
Actual	347,817	1.82% MBT
Deferral (Ann.)	255,523	

Month	Beg. Bal	Deferral / Amort.	Interest	End. Bal
Nov-21	0	255,523	760	256,283
Dec-21	256,283	255,523	2,284	514,090
Jan-22	514,090	255,523	3,817	773,430
Feb-22	773,430	255,523	5,360	1,034,313
Mar-22	1,034,313	255,523	6,911	1,296,748
Apr-22	1,296,748	255,523	8,472	1,560,743
May-22	1,560,743	255,523	10,042	1,826,308
Jun-22	1,826,308	255,523	11,622	2,093,453
Jul-22	2,093,453	255,523	13,211	2,362,187
Aug-22	2,362,187	255,523	14,809	2,632,519
Sep-22	2,632,519	255,523	16,417	2,904,459
Oct-22	2,904,459	255,523	18,034	3,178,016
Nov-22	3,178,016	255,523	19,661	3,453,200
Dec-22	3,453,200	255,523	21,298	3,730,021
Jan-23	3,730,021	(158,261)	5,537	3,577,297
Feb-23	3,577,297	(158,261)	5,306	3,424,341
Mar-23	3,424,341	(158,261)	5,074	3,271,154
Apr-23	3,271,154	(158,261)	4,841	3,117,734
May-23	3,117,734	(158,261)	4,609	2,964,081
Jun-23	2,964,081	(158,261)	4,376	2,810,196
Jul-23	2,810,196	(158,261)	4,142	2,656,077
Aug-23	2,656,077	(158,261)	3,908	2,501,724
Sep-23	2,501,724	(158,261)	3,674	2,347,137
Oct-23	2,347,137	(158,261)	3,440	2,192,316
Nov-23	2,192,316	(158,261)	3,205	2,037,260
Dec-23	2,037,260	(158,261)	2,970	1,881,969
Jan-24	1,881,969	(158,261)	2,734	1,726,442
Feb-24	1,726,442	(158,261)	2,498	1,570,679
Mar-24	1,570,679	(158,261)	2,262	1,414,680
Apr-24	1,414,680	(158,261)	2,026	1,258,445
May-24	1,258,445	(158,261)	1,789	1,101,972
Jun-24	1,101,972	(158,261)	1,551	945,262
Jul-24	945,262	(158,261)	1,314	788,315
Aug-24	788,315	(158,261)	1,076	631,130
Sep-24	631,130	(158,261)	837	473,706
Oct-24	473,706	(158,261)	598	316,043
Nov-24	316,043	(158,261)	359	158,141
Dec-24	158,141	(158,261)	120	0

BEFORE THE PUBLIC UTILITY COMMISSION OF

OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

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Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

OPENING TESTIMONY OF
LANCE D. KAUFMAN
ON BEHALF OF THE
ALLIANCE OF WESTERN ENERGY CONSUMERS

June 22, 2022

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit AWEC/201.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from PacifiCorp.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I provide testimony on PacifiCorp's rate spread, rate design, and depreciation expense.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I make the following recommendations:

- Calculate marginal cost of energy using a wind facility, with the capacity component based on a stand-alone battery storage facility.
- Allocate franchise fees according to proposed revenue rather than current revenue.
- Incorporate a Schedule 48 Greater than 4 MW Primary dedicated substation customer group into the marginal cost study and design consistent rates.
- For Schedule 48, adjust system usage rates to only collect system usage revenue requirement.
- For Schedule 48, maintain current monthly basic charge if the charge would otherwise decrease.

- For Schedule 48, adjust the facility capacity charge for above and below 4,000 kW by equal amounts within each delivery voltage level.
- Maintain the current depreciable life and rate for Colstrip. This reduces system depreciation expense by $12 million
- Extend the depreciable life of Jim Bridger 1 and 2 to 2038 to reflect conversion to gas. This reduces system depreciation expense by $31 million and $16 million respectively.
- Remove Rolling Hills depreciation expense from rates. This reduces system depreciation expense by $8.2 million.
- Remove Labor Day Wildfires depreciation expense from rates. This reduces system depreciation expense by $3 million.

II. MARGINAL COST STUDY

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS TO PACIFICORP'S MARGINAL COST MODEL.

A. I make three recommendations for PacifiCorp's marginal cost model.

1. I recommend renewable capacity and energy costs be accounted for in the marginal generation cost in light of the passage of Oregon House Bill 2021.
2. I recommend franchise fees be allocated based on proposed revenue, and
3. I recommend PacifiCorp implement a dedicated sub transmission rate.

a. <u>Marginal Generation Model Does Not Accurately Reflect Renewable Transition</u>

Q. WHAT IS PACIFICORP'S MARGINAL COST OF GENERATION STUDY INTENDED TO ACCOMPLISH?

A. PacifiCorp's marginal cost of generation study is intended to model the long-run incremental costs of producing one unit of energy.[1] "Long-run" means the model includes fixed costs, such as capital costs for generation facilities, even if PacifiCorp's existing system is large enough to serve an incremental unit of energy. This study is used to allocate generation costs between rate schedules. The intention of a marginal cost study is to assist in developing economically efficient rates by allocating costs on a forward-looking basis, rather than a backwards looking basis. This helps to create price signals for customers that reflect PacifiCorp's forward-looking costs.

Q. HOW DOES PACIFICORP MODEL THE MARGINAL COST OF PRODUCING ENERGY?

A. PacifiCorp models the marginal cost of energy using the cost of a natural gas combustion turbine. This cost is split into capacity and energy components. The capacity component is modeled using the fixed costs of a simple-cycle combustion turbine ("SCCT"). The energy component is the remaining fixed and variable cost of operating a combined cycle combustion turbine ("CCCT").[2]

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1 PAC/1100 Meredith/6:6-7.
2 PAC/1108 Meredith/1.

Q. WILL PACIFICORP ACTUALLY SERVE AN INCREMENTAL UNIT OF ENERGY WITH A CCCT OR SCCT?

A. No, the preferred portfolio in PacifiCorp's 2021 IRP Update adds 24 gigawatts of capacity over the 20-year planning horizon, which is the same length as the marginal cost study.[3] Only 713 MW of this capacity, less than 3 percent, is gas-fired. These limited gas-fired resources are not in fact new combustion turbines, but rather coal fired steam turbines that will be converted to gas. The remaining resource additions are a mixture of demand side management, renewable, storage, nuclear, and hydrogen peaker resources. Over 92 percent of new generating resource additions are renewable.

Q. IS PACIFICORP'S MARGINAL COST MODEL A REASONABLE REPRESENTATION OF THE INCREMENTAL COST OF ENERGY?

A. No. PacifiCorp is not likely to serve incremental energy needs with either CCCT or SCCT resources. These resources do not appear in PacifiCorp's long term resource acquisition plan. Furthermore, the Oregon Legislature's recent passage of House Bill 2021 requires PacifiCorp to reduce its emissions to 80% below "baseline" levels by 2030, increasing to 100% by 2040.[4] That bill also imposed a ban on new natural gas-fired generation in Oregon.[5] This means there is no scenario under current Oregon law where a new combustion turbine, either CCCT or SCCT, will be constructed to serve Oregon load.

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3 PacifiCorp 2021 IRP Update, at 75. There are 1,237 MW of "non-emitting peaker" resource additions fueled by hydrogen. *See* PacifiCorp 2021 IRP, at 172. These resources are not selected until late in the planning period. As such they are speculative and should be given little weight in the cost study.

4 Or. H.B. 2021 § 3(a)-(c).

5 *See Id.* § 28.

Q. WHAT ALTERNATIVES PROVIDE MORE REALISTIC REPRESENTATIONS OF INCREMENTAL ENERGY COSTS?

A. PacifiCorp's IRP shows that incremental energy will likely be served by a mixture of wind and solar generation. The IRP also reveals that PacifiCorp relies on battery storage to provide PacifiCorp's incremental peaking needs.

Q. HOW ARE OTHER UTILITIES ACCOUNTING FOR THE ELEVATED DEMAND COSTS OF LOW CARBON GENERATION?

A. The Washington Utilities and Transportation Commission ("WUTC") recently adopted rules requiring that cost allocations be based on a renewable future peak credit.[6] This approach uses low carbon resources to evaluate both demand and energy costs. Avista's recent implementation of the Washington rules resulted in a 67% demand and 33% energy allocation.[7] My recommendation results in a 84% percent demand and 16% percent energy allocation. My recommendation results in slightly higher demand allocation than the renewable future peak credit model used in Washington.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE MARGINAL COST OF GENERATION?

A. I recommend that the marginal cost of generation be calculated based on the cost of wind generation, as calculated in PacifiCorp's 2021 avoided cost study, and that the capacity component of this cost be based on the cost of a stand-alone battery installation. Implementing this recommendation requires the following specific adjustments to PacifiCorp's model as filed to ensure values are properly calculated:

- CCCT fuel cost is replaced with wind variable O&M, production tax credits, and integration costs.

6/ WAC § 480-85-060(3) Table 2.

7/ See Washington Utilities and Transportation Commission Docket No. UE-200900, Exh. TLK-1T, at 16:20-21.

- Production tax credits are reduced from 20 years to 10 years to be consistent with federal tax law.
- Production tax credits are reduced from 60 percent of full credit to 40 percent of full credit to reflect their continued phase out.
- Capacity cost is based on the total cost per Kw-year for a 50 MW, 200 MWh Li-Ion Battery, as documented in PacifiCorp's 2021 IRP.[8]
- Capacity cost of the battery is reduced by 18% to reflect energy and flexibility value.[9]
- Capacity cost of the battery is divided by the average capacity contribution of a 4-hour battery, 75 percent, to reflect the capacity cost of demand.[10]
- Capacity cost of demand is reduced by 30 percent to reflect the average capacity contribution of Wyoming wind.[11]

The above specific adjustments are necessary to accommodate expectations about production tax credits and to account for the difference in capacity contribution between batteries and wind.

Q. HOW DO YOUR RECOMMENDATIONS COMPARE WITH PACIFICORP'S FILED STUDY?

A. My recommendations increase the cost of capacity and decrease the cost of energy. This is the expected result of Oregon's transition to non-emitting generation. My recommendation also

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8 Exhibit AWEC/202, Response to AWEC Data Request 086; PacifiCorp's 2021 IRP, Volume I, Chapter 7 (Resource Options), at 177.

9 Calculated from PacifiCorp's 2021 IRP Volume II, Appendix N, at 237.

10 PacifiCorp's 2021 IRP Table K.1 provides capacity contribution. PacifiCorp's avoided cost workpaper included in this filing (7_OR Standard QF AC Study_2021 09 10 (Effective 2021 11 03).xlsx) provides the summer and winter weightings for capacity contribution.

11 PacifiCorp's 2021 IRP Table K.1 provides capacity contribution. PacifiCorp's avoided cost workpaper included in this filing (7_OR Standard QF AC Study_2021 09 10 (Effective 2021 11 03).xlsx) provides the summer and winter weightings for capacity contribution.

decreases the allocated cost of generation for schedules with low coincident peak demand relative to energy and increases the allocated cost of generation for customers with high coincident peak demand relative to energy. The table below compares the allocation of generation revenue requirement under PacifiCorp's gas-based marginal cost model, and PacifiCorp's same model after replacing emitting resources with non-emitting resources. These values are based on PacifiCorp's filed revenue requirement.

Table 1 Generation Marginal Cost Change Impact

Generation and Ancillary Services Allocation (in $1000)					
			PAC	AWEC	Change
Residential		(sec)	331,799	365,471	33,672
General Service	Sch 23	(sec)	62,910	62,549	(362)
		(pri)	173	157	(16)
General Service	Sch 28	(sec)	107,862	104,697	(3,166)
		(pri)	1,274	1,218	(56)
General Service	Sch 30	(sec)	63,561	59,309	(4,252)
		(pri)	5,271	5,042	(229)
Large Power Service	Sch 48	(sec)	29,097	26,709	(2,388)
		(pri)	75,267	66,048	(9,219)
		(trn)	75,989	64,016	(11,974)
Irrigation	Sch 41	(sec)	13,965	12,658	(1,307)
Lighting	Schs 15, 51, 53, and 54		909	206	(703)

Q. DO YOU RECOMMEND THAT THE COMMISSION FULLY IMPLEMENT YOUR CHANGES IN THIS RATE CASE?

A. Yes. In Exhibit AWEC/100, AWEC witness Bradley Mullins proposes a decrease to overall revenue requirement. Given this recommended decrease, the Commission could move rates directly to the revised result of the marginal cost study without adversely impacting residential customers. The increase to residential customer rates under my recommended marginal cost model and AWEC's proposed revenue requirement is smaller than under PacifiCorp's filed case. However, if the Commission approves the revenue requirement as filed by PacifiCorp, it may be appropriate to partially offset the impact of my recommended marginal cost study through use of the Rate Mitigation Adjustment to avoid rate shock.

b. Allocation of franchise fees should be forward looking

Q. WHAT ARE FRANCHISE FEES?

A. Franchise fees are fees paid by PacifiCorp and other utilities to local governments for the use of rights-of-way. Franchise fees are typically expressed as a percentage of billed revenue.

Q. HOW DOES PACIFICORP ALLOCATE THE COST OF FRANCHISE FEES?

A. PacifiCorp allocates franchise fees based on revenue under present rates rather than proposed rates. This means that the allocation of franchise fees is backwards looking rather than forwards looking. As a result, the allocation of franchise fees does not reflect the driver of franchise fees.

Q. HOW DOES PACIFICORP'S ALLOCATION MISREPRESENT REALITY?

A. Under PacifiCorp's allocation, a customer class could experience an increase in allocation of franchise fees even if they have no increase in expected billed revenue. To illustrate this, consider a situation where forecasted franchise fees are increasing due to customer growth of a single schedule, such as residential, while another schedule, say irrigation, has no growth. A backward-looking model such as PacifiCorp's would allocate the cost increase to both residential and irrigation customers, even though irrigation customers did not cause any increase in franchise fees. A forward-looking allocation would recognize the expected increase in residential revenue, and irrigation customers would not be allocated any of the increase in franchise fee costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING FRANCHISE FEES?

A. I recommend franchise fees be allocated based on the total allocated functionalized revenue, excluding franchise fees. The impact of this recommendation is summarized below. These values are based on PacifiCorp's filed revenue requirement.

Table 2 Franchise Fee Marginal Cost Change Impact

Franchise Fees Allocation (in $1000)					
			PAC	AWEC	Change
Residential		(sec)	$ 15,740	$ 18,012	$ 2,271
General Service	Sch 23	(sec)	3,272	3,674	402
		(pri)	9	9	0
General Service	Sch 28	(sec)	4,262	3,672	(590)
		(pri)	55	38	(17)
General Service	Sch 30	(sec)	2,293	1,790	(502)
		(pri)	191	147	(44)
Large Power Service	Sch 48	(sec)	1,080	869	(211)
		(pri)	2,532	1,838	(693)
		(trn)	2,304	1,481	(823)
Irrigation	Sch 41	(sec)	770	981	211
Lighting	Schs 15, 51, 53, and 54		136	132	(4)

c. <u>PacifiCorp Should Offer a Dedicated Substation Rate under Schedule 48</u>

Q. WHAT IS A DEDICATED SUBSTATION?

A. A dedicated substation is a substation that serves only one customer.

Q. WHAT IS YOUR CONCERN WITH DEDICATED SUBSTATION CUSTOMERS?

A. PacifiCorp serves five customers through dedicated substations under the Schedule 48, Greater than 4 MW, Primary rate. These customers have a distinctly different cost profile relative to other customers served under this rate. In response to Order 20-473, PacifiCorp conducted a study of the cost of serving these customers. PacifiCorp found that the distribution cost, on a cost per kW basis, for serving dedicated customers was half the cost of serving other customers on the Schedule 48, greater than 4 MW, Primary rate. PacifiCorp does not appear to have applied the findings from its distribution cost study, and thus the five customers with dedicated substations are not benefitting from the additional knowledge and information PacifiCorp has acquired regarding the operations of its distribution system.

Q. DOES PACIFICORP'S STUDY PERFORMED IN RESPONSE TO ORDER 20-473 DEMONSTRATE THAT CUSTOMERS SERVED THROUGH DEDICATED SUBSTATIONS ARE SUBSIDIZING OTHER CUSTOMERS?

A. Yes, PacifiCorp's study shows that these customers are paying above their cost of service for distribution services.

Q. WHAT IS YOUR RECOMMENDATION REGARDING DEDICATED SUBSTATION CUSTOMERS?

A. I recommend PacifiCorp include a dedicated substation customer group for Schedule 48 in its marginal cost study and develop corresponding rates. PacifiCorp's model developed in response to Order 20-473 creates a dedicated substation subgroup for schedule 48; however, the model is based on 2021 billing determinants rather than 2023 and does not reflect the proposed revenue requirement. PacifiCorp declined to update the study to reflect the current rate case.[12] At present, I have been unable to update the model to reflect the filed case. However, I am continuing to analyze the model and have requested assistance from PacifiCorp. I intend to present the revised model in rebuttal testimony.

III. RATE DESIGN

Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO PACIFICORP'S RATE DESIGN.

A. I recommend three adjustments to the rate design model developed by PacifiCorp. All three recommendations are limited to Schedule 48.

[12] Exhibit AWEC/202, Response to AWEC Data Request 085.

- Adjust system usage rates to only collect system usage revenue requirement. This ensures that the functionalization of revenue requirement into unbundled components is preserved in rates and reduces the potential for cost shifting due to direct access load.
- Maintain the current monthly basic charge if the charge would otherwise decrease. This adjustment is consistent with the filed treatment of transmission rates, which are set equal to present rates.
- Adjust the facility capacity charge for above and below 4,000 kW by equal amounts within each delivery voltage level. This ensures rates do not move in opposite directions for above and below 4,000 kW customers without a cost basis.

IV. COAL PLANT DEPRECIABLE LIVES

Q. WHAT ISSUES DOES PACIFICORP RAISE REGARDING COAL PLANT DEPRECIABLE LIVES?

A. PacifiCorp has requested several coal plant depreciable lives be adjusted and that depreciation rates be revised accordingly. PacifiCorp proposes shortening the depreciable life of Colstrip 3 and 4 from 2027 to 2025, extending Craig 2 from 2026 to 2028, extending Hayden 1 from 2023 to 2028 and Hayden 2 from 2023 to 2027.[13]

Q. WHAT OTHER COAL LIFE ISSUES DOES PACIFICORP RAISE?

A. PacifiCorp also notes that it has changed the retirement plans for Bridger 1 and 2. The current depreciable lives for these units are 2023 and 2025 respectively. PacifiCorp plans to convert these plants to gas and operate them until 2038.[14]

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13 Exhibit PAC/1002 Cheung/169.
14 PacifiCorp 2021 IRP Update, at 75.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THESE PLANTS?

A. I recommend the depreciable life of Colstrip be maintained at 2027. I support updating the lives of Craig 2 and Hayden 1 and 2. I also recommend the depreciable lives of Jim Bridger 1 and 2 each be extended to 2038.

Q. WHY DO YOU RECOMMEND MAINTAINING THE CURRENT DEPRECIABLE LIFE OF COLSTRIP?

A. In Order No. 20-473 the Commission noted that "extended depreciable lives does not preclude earlier retirement if such early retirement is demonstrated to be economic in the future." I agree with the Commission that a depreciable life of 2027 does not preclude early retirement in 2025. However, because PacifiCorp is a minority owner in Colstrip, it has limited ability to influence the actual retirement date of this plant. Consistent with the 2020 Protocol, the Commission adopted an Exit Order for Colstrip at 2027, which strikes the right balance between cost and risk for customers, given the uncertainty over this plant's operating life.[15]

It is important to remember that this case is not being decided in a vacuum. Customers are also looking at substantial rate increases from the Company's Transition Adjustment Mechanism filing, its Power Cost Adjustment Mechanism filing, and have not yet begun paying for incremental decommissioning and remediation costs that are continuing to be addressed in UM 2183. Further accelerating Colstrip's depreciable life further increases rates for customers without any assurance that 2025 will better match Colstrip's operating life.

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[15] Docket No. UE 374, Order No. 20-473, at 12-13 (Dec. 18, 2020).

Q. WHY DO YOU SUPPORT EXTENDING THE DEPRECIABLE LIFE OF CRAIG AND HAYDEN?

A. While PacifiCorp's recommendation for Colstrip is contrary to the expected retirement date of that facility, PacifiCorp's recommendation for Craig and Hayden is consistent with the expected retirement dates of these two generation stations.

Q. WHY DO YOU RECOMMEND THE DEPRECIABLE LIFE OF JIM BRIDGER 1 AND 2 BE EXTENDED TO 2038?

A. Jim Bridger 1 and 2 will be converted to gas plants in 2024. This conversion will leverage the Jim Bridger existing facilities. The reason gas conversion was selected over retirement and replacement by an SCCT is because conversion is less expensive.[16] Conversions are less expensive because of the existing infrastructure already invested at the plant. It is appropriate for the costs of this existing infrastructure to be spread over the useful life of the infrastructure.

By the time rates approved in this case are implemented in 2023, the remaining net book value of these plants will be less than 20 percent of the original investment. This is an appropriately small share of the original plant to incorporate into the base capital cost of the gas conversion.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS?

A. The table below summarizes the depreciation expense impact by plant for my recommendations. The calculations for Jim Bridger 1 and 2 are approximate and should be recalculated by PacifiCorp in a similar manner as was done for Craig and Hayden. The total system reduction to depreciation expense is $58 million. The Oregon allocation of this reduction is $15.2 million.

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16 PacifiCorp 2021 IRP, at 253.

Table 3: Depreciable Life Change Impact on Depreciation Expense

	PROPOSED END OF DEPRECIABLE LIFE	AS OF DEC 31, 2022		PAC Proposed		COMPOSITE REMAINING LIFE	AWEC Proposed		CHANGE
		ORIGINAL COST	FUTURE ACCURALS	ANNUAL AMOUNT	ACCRUAL RATE		ACCRUAL RATE	ANNUAL AMOUNT	
Colstrip	12-2025	245,683,766	71,638,975	25,796,827	10.50	2.8	5.71	13,996,713	(11,800,114)
Jim Bridger 1	12-2038	247,195,302	31,572,421	32,782,607	13.26	16.0	0.80	1,973,276	(30,809,331)
Jim Bridger 2	12-2038	252,527,466	55,642,967	19,207,105	7.61	16.0	1.38	3,477,685	(15,729,420)
System Total		**745,406,534**	**158,854,363**	**77,786,539**				**19,447,675**	**(58,338,864)**
Oregon Allocation Factor									26.070%
Oregon Allocated									**(15,209,141)**

V. OTHER DEPRECIATION EXPENSE ADJUSTMENTS

Q. WHAT OTHER DEPRECIATION EXPENSE ADJUSTMETNS DO YOU PROPOSE?

A. I recommend adjusting depreciation expense related to two rate base adjustments made by PacifiCorp for the Rolling Hills and Labor Day fires. PacifiCorp makes these adjustments to plant in its filed case but does not appear to have matching depreciation expense adjustments.

Q. PLEASE DESCRIBE THE ROLLING HILLS ADJUSTMENT.

A. Adjustment 8.9 removes the Rolling Hills wind facility from Oregon rates. The note for the adjustment states that depreciation expense for Rolling Hills is removed in Adjustment 6.1. However, Adjustment 6.1 makes no mention of Rolling Hills, and the adjustment increases rather than decreases Other Production depreciation expense. I calculate the Rolling Hills depreciation expense by multiplying the Rolling Hills gross plant adjustment by the overall depreciation accrual rate for other production, 4.23. The table below summarizes the Rolling Hills depreciation adjustment. The adjustment reduces system depreciation expense by $8.2 million and Oregon allocated depreciation expense by $2.1 million.

Table 4: Rolling Hills Depreciation Exclusion Change

Depreciation Expense	FERC Account	EOP Jun 2021
Depreciation Rate	403OP	4.22%
Other Depreciation Expense	403OP	8,240,654
Oregon Allocation Factor		26.07%
Oregon Allocated		2,148,367

Q. PLEASE DESCRIBE THE LABOR DAY WILDFIRE ADJUSTMENT.

A. The Labor Day Wildfires were a series of wildfires in the fall of 2020 that damaged PacifiCorp's facilities in Oregon and California. PacifiCorp has been accused of negligence and is involved in civil litigation concerning these fires. PacifiCorp has removed the plant investment associated with these fires in Adjustment 8.17. However, this adjustment does not include a reduction to depreciation expense. I recommend that depreciation expense also be excluded from rates.

Q. WHY DO YOU RECOMMEND THAT DEPRECIATION EXPENSE BE EXCLUDED FROM RATES?

A. PacifiCorp has filed to exclude the plant associated with the Labor Day fires from rates. For consistency, the depreciation costs associated with the plant should also be excluded from rates.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT?

A. The table below summarizes my adjustment. I calculate depreciation expense using depreciation rates approved in UM 1968 and plant balances reported in PacifiCorp's adjustment 8.17. The adjustment reduces system depreciation expense by $3 million and Oregon depreciation expense by $1.4 million.

Table 5: Wildlife Fire Depreciation Expense Change

Adjustment to Depr. Expense:	**Acct.**	**Rate**	**System**			**Oregon**
Transmission Plant	355	2.15	(1,931,822)	SG	26.070%	(503,633)
Distribution Plant	360	1.15	(4,954)	OR	Situs	(4,052)
Distribution Plant	361	2.04	(16,659)	OR	Situs	(13,624)
Distribution Plant	362	3.13	(212,083)	OR	Situs	(173,449)
Distribution Plant	364	2.08	(184,189)	OR	Situs	(150,637)
Distribution Plant	365	1.75	(97,515)	OR	Situs	(79,751)
Distribution Plant	366	1.99	(55,015)	OR	Situs	(44,994)
Distribution Plant	367	2.29	(147,688)	OR	Situs	(120,784)
Distribution Plant	368	1.98	(193,288)	OR	Situs	(158,078)
Distribution Plant	369	2.09	(126,165)	OR	Situs	(103,182)
Distribution Plant	370	1.71	(28,256)	OR	Situs	(23,109)
Distribution Plant	371	4.32	(2,468)	OR	Situs	(2,019)
Distribution Plant	373	2.48	(10,147)	OR	Situs	(8,299)
Total			(3,010,249)			(1,385,610)

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/201

CURRICULUM VITAE OF LANCE D. KAUFMAN

CURRICULUM VITAE

LANCE KAUFMAN
Aegis Insight
4801 W. Yale Ave.
Denver, Colorado 80219
(541) 515-0380
lance@aegisinsight.com

EDUCATION:

University of Oregon	Ph.D.	Economics	2008 – 2013
University of Oregon	M.S.	Economics	2006 – 2008
University of Anchorage Alaska	B.B.A.	Economics	2001 – 2004

CERTIFICATIONS:

Certified Depreciation Professional	Society of Depreciation Professionals	2018

PROFESSIONAL EXPERIENCE:

Principal Economist	Aegis Insight	2014 – Present
Senior Economist	Oregon Public Utility Commission	2015 – 2018
Public Utility Advocate	Alaska Department of Law	2014 – 2015
Senior Economist	Oregon Public Utility Commission	2013 – 2014
Instructor	University of Oregon	2008 – 2012
Research Assistant	University of Alaska Anchorage	2003 – 2008

PROFESSIONAL MEMBERSHIPS:

Society of Depreciation Professionals	2015 – Present
American Economic Association	2017 – Present

RESEARCH, CONSULTING, AND ECONOMETRIC ANALYSIS:

- Baumgartner Law, LLC, Denver, CO, 2021
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to injury in re In Re: Bernadette Romero and Leonard Martinez v. City of Westminster
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Retained as expert witness for plaintiff re racial disparities in police use of force re Estate of Elijah J. McClain V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Fortson, et al. v. Garrison Property and Casualty Insurance Co. United States District Court Middle District of North Carolina Civil Action No. 1:19-cv-294.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Lewis and Lewis, et al. v. Government Employees Insurance Co. United

States District Court For the District of New Jersey Civil Action No. 1:18−CV−05111−RBK−AMD.

- Cable Huston, LLP, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Cascade Natural Gas Corporation Request for General Rate Revision, Public Utility Commission of Oregon, Docket No. UG 390.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Power Cost Update Tariff, Public Utility Commission of Oregon, Docket No. UE 377.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net power costs in Portland General Electric Company 2021 Annual Update Tariff, Public Utility Commission of Oregon, Docket No. UE 381.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding revenue requirement, rate spread and rate design in Nevada Power Company 2021 General Rate Case, Public Utility Commission of Nevada, Docket No. 20-06003
- Frank & Salahuddin LLC, Denver, Colorado, 2020
  Retained as an expert witness for plaintiffs regarding calculation of lost earnings due to wrongful death.
- Level Development Group, LLC, Denver, Colorado, 2020
  Develop real estate valuation model for establishing sale price of newly constructed residential housing.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in Jeff Olberg v. Allstate Insurance Company, Case No. C18-0573-JCC, United States District Court, Western District of Washington at Seattle.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2020
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Cameron Lundquist v. First National Insurance Company of America, Case No. 18-cv-05301-RJB, United States District Court, Western District of Washington at Tacoma.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2020
  Deposed as expert witness for plaintiff re racial disparities in police use of force re Brandon Washington V. City Of Aurora, Colorado, Case No. 1:19-cv-01160-RM-MEH, United States District Court, District of Colorado.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding coal plant pollution control investments, coal plant decommissioning costs, rate spread and rate design re PacifiCorp 2020 Request for a General Rate Revision, Public Utility Commission of Oregon Docket No. UE 374.
- Davison Van Cleve, PC, Portland, OR and Washington Attorney General, 2020

Retained as an expert witness for Packaging Company of America and Washington Public Council regarding decommissioning costs and rate design re PacifiCorp 2020 Request for a General Rate Revision, Washington Utility and Transportation Commission.

- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Renewable Energy Coalition and for Northwest & Intermountain Power Producers Coalition to provide analysis of PacifiCorp avoided costs in a Utility PURPA Compliance Filing at the Washington Utility and Transportation Commission Docket, No. UE-190666.
- Sanger Law, PC, Portland, OR, 2019
  Retained as a consultant for Northwest & Intermountain Power Producers Coalition to provide analysis of Portland General Electric avoided costs in support of testimony to the Oregon Legislature.
- Powder River Basin Resource Council, Laramie, Wyoming, 2019.
  Testified as an expert witness for Powder River Basin Resource Council regarding coal plant closures re PacifiCorp 2019 Integrated Resource Plan, Wyoming Public Service Commission Docket No. 90000-147-XI-19.
- The Law Office of Ralph Lamar, Arvada, CO 2019
  Deposed as an expert witness for plaintiffs regarding lost profits of a Farmers insurance agency
- Jester, Gibson & Moore, Denver, CO 2019
  Retained as an expert witness for plaintiffs regarding lost earnings in an ADEA wrongful termination matter.
- Albrechta & Coble, Ltd. Fremont, OH 2019
  Retained as an expert witness for plaintiff regarding lost earnings in Perez v. CAPCO, a race related wrongful termination matter.
- Conrad Law, PC, Salt Lake City, UT 2019
  Retained as an expert witness for Ellis-Hall Consultants, LLC. regarding economic damages in Ellis-Hall Consultants, LLC. et. al. v. George B. Hofmann IV, United States District Court, District of Utah, Central Division.
- Davison Van Cleve, PC, Portland, OR 2019
  Retained as an expert witness for Alliance of Western Energy Consumers regarding net variable power cost calculations in PORTLAND GENERAL ELECTRIC COMPANY, 2020 Annual Power Cost Update Tariff Public Utility Commission of Oregon Docket No. UE 359.
- Sanger Law, PC, Portland, OR, 2019
  Testified as an expert witness for Renewable Energy Coalition and Rocky Mountain Coalition for Renewable Energy regarding Qualified Facility avoided costs in Application of Rocky Mountain Power for a Modification of Avoided Cost Methodology and Reduced Term of PURPA Power Purchase Agreements Public Service Commission of Wyoming Docket No. 20000-545-ET-18
- Sanger Law, PC, Portland, OR, 2019
  Retained as an expert witness for Cafeto Coffee Company regarding the necessity, design, and location of transmission lines in SPRINGFIELD UTILITY BOARD Petition for

Certificate of Public Convenience and Necessity Public Utility Commission of Oregon Docket No. PCN 3.

- Baumgartner Law, LLC, Denver, CO, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to injury in re Eric Bowman, v. Top Tier Colorado, LLC,, Case No. 18CV31359, United States District Court, District of Colorado.
- Cohen Milstein Sellers & Toll PLLC, Washington DC, 2018
  Retained as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Isaac Harris et al. v. Medical Transportation Management, Inc., Civil Action No. 17-1371, United States District Court, District of Columbia.
- Davison Van Cleve, PC, Portland, OR 2020
  Retained as an expert witness for Alliance of Western Energy Consumers regarding depreciation rates in re PacifiCorp Application for Authority to Implement Revised Depreciation Rates, Public Utility Commission of Oregon Docket No. UM 1968.
- Davison Van Cleve, PC, Salem, OR and Washington Attorney General, OR 2020
  Retained as an expert witness for Packaging Company of America and Washington Public Council regarding depreciation rates in re Pacific Power 2018 Depreciation Study, Washington Utility and Transportation Commission, Docket No. UE-180778.
- Hagens Berman Sobol Shapiro LLP, Phoenix, Arizona, 2018
  Deposed as an expert witness for plaintiffs re calculation of economic harm due to breach of contract in re Vicky Maldonado and Carter v. Apple Inc., AppleCare Services Company, Inc., and Apple CSC, Inc., Case No. 3:16-cv-04067-WHO, United States District Court, District of California.
- Hagens Berman Sobol Shapiro, LLP, Phoenix, Arizona, 2018
  Deposed and testified as an expert witness for plaintiffs re calculation of unpaid mileage for truck drivers in re Swift Transportation Co., Inc., Civil Action No. CV2004-001777, Superior Court of the State of Arizona, County of Maricopa.
- Killmer, Lane, and Newman, LLP, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re reasonable attorney fees in re Jeanne Stroup and Ruben Lee, v. United Airlines, Inc., Case No. 15-cv-01389-WYD-STV, United States District Court, District of Colorado.
- Klein and Frank, PC, Denver, Colorado, 2018
  Retained as expert witness for plaintiffs re potential jury bias in re Gail Goehrig and Chris Goehrig v. Core Mountain Enterprises, LLC, Case No. 2016CV030004, San Juan County District Court.
- Robert Belluso, Pennsylvania, 2017
  Retained as expert witness for plaintiff re lost profit in re Robert Belluso D.O. v Trustees of Charleroi Community Park, PHRC Case No. 201505365, Pennsylvania Human Relations Commission.
- Lowery Parady, LLC, Denver, Colorado, 2017
  Analyzed payroll data and calculated unpaid overtime and unpaid hours for plaintiff class action in re Violeta Solis, et al. v. The Circle Group, LLC, et al., Case No. 1:16-cv-01329-RBJ, United States District Court, District of Colorado.
- Sawaya & Miller Law Firm, Denver, Colorado, 2017
  Provided data processing and analysis of employment records.

- Financial Scholars Group, Orinda, California, 2017
  Provided analysis of risk profile in bundled real estate and personal loans in re Old Republic Insurance Company v. Countrywide Bank et al., Circuit Court of Cook County, Illinois, Chancery Division.
- Financial Scholars Group, Orinda, California, 2017
  Provided consultation and analysis of financial market transactions in preparation of settlement claims filings in re Laydon v. Mizuho Bank, Ltd., et al. and Sonterra Capital Master Fund Ltd., et al v. UBS AG et al.
- Clean Energy Action, Boulder, Colorado, 2016 – 2017
  Provided consultation on the appropriate discounting methodology used in energy resource planning in the Public Service Company of Colorado application for approval of the 2016 Electric Resource Plan, Proceeding No. 16A-0396E, Public Utilities Commission of the State of Colorado.
- Confidential Client, 2016
  Provided analysis and report on the probability that distinct crimes are independent events based on geographical analysis of crime rates.
- Christine Lamb and Kevin James Burns, Denver, Colorado, 2016
  Provided data analysis for defendant of the impact of ethnicity on termination decisions in re Aragon et al v. Home Depot USA, Inc., Case No. 1:15-cv- 00466-MCA-KK, United States District Court, District of New Mexico.
- Steptoe & Johnson LLP, Washington, DC, 2015 – 2016
  Programmed analysis of internet traffic data for plaintiffs applying a proprietary probability model developed to identify and verify accounts responsible for repeated infringements of asserted copyrights by defendants' internet subscribers in re BMG Rights Management (US) LLC, and Round Hill Music LP v. Cox Enterprises, Inc., et al., Case No. 1:14-cv-1611(LOG/JFA), United States District Court Eastern District of Virginia, Alexandria Division.
- Padilla & Padilla, PLLC, Denver, Colorado, 2014 – 2016
  Provided research and analysis for plaintiffs re the impact on minority applicants from use of the AccuPlacer Test by the City and County of Denver, and estimated damages in re Marian G. Kerner et al. v. City and County of Denver, Civil Action No. 11-cv-00256-MSK-KMT, United States District Court, District of Colorado.
- U.S. Equal Employment Opportunity Commission, 2013
  Provided statistical analysis of EEOC filings.

OTHER REGULATORY PROCEEDINGS:

- Portland General Electric 2016 Annual Power Cost Variance Docket No. UE 329.
- PacifiCorp 2016 Power Cost Adjustment Mechanism Docket No. UE 327.
- Public Utility Commission of Oregon Staff Investigation into the Treatment of New Facility Direct Access Charges Docket No. UM 1837
- PacifiCorp Oregon Specific Cost Allocation Investigation Docket No. UM 1824.
- PacifiCorp 2018 Transition Adjustment Mechanism Docket No. UE 323.
- Portland General Electric 2018 General Rate Case Docket No. UE 319.
- Avista Corp. 2017 General Rate Case Docket No. UG 325.

- Portland General Electric Affiliated Interest Agreement with Portland General Gas Supply Docket No. UI 376.
- Portland General Electric 2017 Automated Update Tariff Docket No. UE 308
- PacifiCorp 2017 Transition Adjustment Mechanism Docket No. UE 307
- Portland General Electric 2017 Reauthorization of Decoupling Adjustment Docket No. UE 306
- Northwest Natural Gas Investigation of WARM Program Docket No. UM 1750.
- PacifiCorp Investigation into Multi-Jurisdictional Allocation Issues Docket No. UM 1050.
- Idaho Power Company 2015 Power Supply Expense True Up Docket No. UE 305
- Homer Electric Association 2015 Depreciation Study U-15-094
- Submitted prefiled testimony regarding the depreciation study.
- Chugach Electric Association 2015 Rate Case U-15-081
- Developed staff position regarding margin calculations.
- ENSTAR 2014 Rate Case U-14-111
- Submitted prefiled testimony regarding sales forecast.
- Alaska Pacific Environmental Services 2014 Rate Case U-14-114/115/116/117/118
  Submitted prefiled testimony regarding cost allocations, cost of service, cost of capital, affiliated interests, and depreciation.
- Alaska Waste 2014 Rate Case U-14-104/105/106/107
  Submitted prefiled testimony regarding cost of service study, cost of capital, operating ratio, and affiliated interest real estate contracts.
- Fairbanks Natural Gas 2014 Rate Case U-14-102
  Submitted prefiled testimony regarding cost of service study and forecasting models.
- Avista 2015 Rate Case U-14-104
  Submitted analysis supporting OPUC Staff settlement positions regarding Avista's sales and load forecast, decoupling mechanisms and interstate cost allocation methodology. Represented Staff in settlement conferences on November 21, November 26, and December 4, 2013.
- Portland General Electric 2015 Rate Case
  Submitted pre-filed opening testimony addressing PGE's sales forecast, printing and mailing budget forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge. Represented OPUC Staff in settlement conferences on May 20, May 27, and June 12, 2014.
- Portland General Electric 2014 General Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PGE's sales and load forecast, revenue decoupling mechanism, and cost of service study. Represented OPUC Staff in settlement conferences on May 29, June 3, June 6, July 2, and July 9 of 2013. Submitted testimony in support of partial stipulation, pre-filed opening testimony addressing PGE's decoupling mechanism, and testimony in support of a second partial stipulation.
- PacifiCorp 2014 General Electric Rate Case
  Submitted analysis supporting OPUC Staff settlement positions regarding PacifiCorp's sales and load forecast and cost of service study. Represented Staff in settlement conferences on June 12 through June 14, 2013.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

Request for a General Rate Revision (UE 399),

Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program (UM 1964),

Application to Defer Costs Relating to Cedar Springs II (UM 2134),

Application for Approval of Deferred Accounting for Cholla Unit 4-Related Property Tax Expense (UM 2142),

Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/202

DISCOVERY RESPONSES

UE 399 / PacifiCorp
June 21, 2022
AWEC Data Request 085

AWEC Data Request 085

Please update the "OR GRC MC Study Dec 2021 - ORDER - Subgroup for Dedicated Substation Customers" model to reflect the assumptions used in the marginal cost study filed with this case.

Response to AWEC Data Request 085

PacifiCorp objects to this data request on the basis that it requests an analysis that the Company has not performed. PacifiCorp has provided sufficient information for a party to conduct its own analysis.

UE 399 / PacifiCorp
June 21, 2022
AWEC Data Request 086

AWEC Data Request 086

Please refer to the PacifiCorp 2021 IRP, pages 11 and 172. Please identify the battery resource type selected for standalone battery storage in the preferred portfolio.

Response to AWEC Data Request 086

The standalone battery storage selected in PacifiCorp's 2021 Integrated Resource Plan (IRP) is the lithium-ion 50 megawatt (MW) and 200 megawatt-hour (MWh) which reflects a four-hour battery duration. In PacifiCorp's 2021 IRP, Volume I, Chapter 7 (Resource Options), page 172, this proxy resource is listed as "Li-Ion Battery, , 50MW, 200MW" in Table 7.1 (2021 Supply-Side Resource Table (2020$) (Continued)).

PacifiCorp's 2021 IRP is publicly available and can be accessed by utilizing the following website link:

Integrated Resource Plan (pacificorp.com)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, UM 2201

In the Matters of

PACIFICORP dba PACIFIC POWER,

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Application for Approval of Deferred Accounting for Revenues Associated with Renewable Energy Credits from Pryor Mountain, (UM 2167),

Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans (UM 2185),

Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120 (UM 2186), and

Alliance of Western Energy Consumers, Application for an Accounting Order Requiring PacifiCorp to Defer Fly Ash Revenues (UM 2201).

EXHIBIT AWEC/203

MARGINAL COST AND RATE SPREAD

Generation and Ancillary Services Allocation (in $1000)					
			PAC	AWEC	Change
Residential		(sec)	331,799	365,471	33,672
General Service	Sch 23	(sec)	62,910	62,549	(362)
		(pri)	173	157	(16)
General Service	Sch 28	(sec)	107,862	104,697	(3,166)
		(pri)	1,274	1,218	(56)
General Service	Sch 30	(sec)	63,561	59,309	(4,252)
		(pri)	5,271	5,042	(229)
Large Power Service	Sch 48	(sec)	29,097	26,709	(2,388)
		(pri)	75,267	66,048	(9,219)
		(trn)	75,989	64,016	(11,974)
Irrigation	Sch 41	(sec)	13,965	12,658	(1,307)
Lighting	Schs 15, 51, 53, and 54		909	206	(703)

Franchise Fees Allocation (in $1000)					
			PAC	AWEC	Change
Residential		(sec)	$ 15,740	$ 18,012	$ 2,271
General Service	Sch 23	(sec)	3,272	3,674	402
		(pri)	9	9	0
General Service	Sch 28	(sec)	4,262	3,672	(590)
		(pri)	55	38	(17)
General Service	Sch 30	(sec)	2,293	1,790	(502)
		(pri)	191	147	(44)
Large Power Service	Sch 48	(sec)	1,080	869	(211)
		(pri)	2,532	1,838	(693)
		(trn)	2,304	1,481	(823)
Irrigation	Sch 41	(sec)	770	981	211
Lighting	Schs 15, 51, 53, and 54		136	132	(4)

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2023 Unbundled Revenue Requirement Allocation by Load Class

Line	Description	Total	(A) Residential (sec)	(B) General Service Sch 23 (sec)	(C) General Service Sch 23 (pri)	(D) General Service Sch 28 (sec)	(E) General Service Sch 28 (pri)	(F) General Service Sch 30 (sec)	(G) General Service Sch 30 (pri)	(H) Large Power Service Sch 48 (sec)	(I) Large Power Service Sch 48 (pri)	(J) Large Power Service Sch 48 (trn)	(K) Irrigation Sch 41 (sec)	(L) Lighting Schs 15, 51, 53, and 54	Lighting Detail Schs 15 & 51 (sec)	Lighting Detail Sch 53 (sec)	Lighting Detail Sch 54 (sec)
1	Total Operating Revenues	$1,238,175	$597,063	$124,106	$332	$161,664	$2,068	$86,965	$7,232	$40,979	$96,027	$87,395	$29,194	$5,151	$4,413	$657	$82
2	MWh	13,886,900	5,633,856	1,133,687	3,324	1,968,466	23,804	1,183,142	98,439	545,911	1,464,317	1,545,236	263,565	23,152	10,559	11,452	1,141
3																	
4	Functionalized 20 Year Full Marginal Costs - Class $																
5	Generation	$726,456	$345,666	$59,159	$149	$99,023	$1,152	$56,095	$4,768	$25,261	$62,469	$60,547	$11,972	$194	$89	$96	$10
6	Transmission	$10,329	$5,047	$840	$2	$1,396	$16	$781	$67	$350	$852	$814	$165	$0	$0	$0	$0
7	Distribution	$376,144	$239,641	$57,315	$49	$33,082	$207	$11,180	$760	$6,785	$8,397	$0	$18,509	$218	$203	$5	$9
8	Distribution-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326	$6,326	$0	$0
9	Customer - Billing	$16,770	$13,431	$2,556	$3	$366	$2	$26	$2	$27	$26	$2	$132	$196	$185	$8	$3
10	Customer - Metering	$16,150	$12,418	$2,132	$134	$632	$80	$133	$62	$20	$104	$159	$273	$3	$0	$0	$3
11	Customer - Other	$5,964	$4,955	$774	$1	$106	$1	$11	$1	$4	$4	$0	$41	$66	$62	$3	$1
12	Total	$1,158,139	$621,158	$122,776	$339	$134,605	$1,458	$68,226	$5,660	$32,447	$71,851	$61,522	$31,093	$7,002	$6,864	$113	$25
13																	
14	Functional Revenue Requirement Allocation Factors																
15	Functionalized 20 Year Full Marginal Costs - Class % of Total																
16	Generation	100.00%	47.58%	8.14%	0.02%	13.63%	0.16%	7.72%	0.66%	3.48%	8.60%	8.33%	1.65%	0.03%	0.01%	0.01%	0.00%
17	Transmission	100.00%	48.86%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.39%	8.25%	7.88%	1.60%	0.00%	0.00%	0.00%	0.00%
18	Distribution	100.00%	63.71%	15.24%	0.01%	8.80%	0.06%	2.97%	0.20%	1.80%	2.23%	0.00%	4.92%	0.06%	0.05%	0.00%	0.00%
19	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%	0.00%
20	Ancillary Service	100.00%	47.58%	8.14%	0.02%	13.63%	0.16%	7.72%	0.66%	3.48%	8.60%	8.33%	1.65%	0.03%	0.01%	0.01%	0.00%
21	Customer - Billing	100.00%	80.09%	15.24%	0.02%	2.18%	0.01%	0.16%	0.01%	0.16%	0.15%	0.01%	0.79%	1.17%	1.10%	0.05%	0.02%
22	Customer - Metering	100.00%	76.89%	13.20%	0.83%	3.92%	0.50%	0.82%	0.38%	0.12%	0.64%	0.99%	1.69%	0.02%	0.00%	0.00%	0.02%
23	Customer - Other	100.00%	83.09%	12.98%	0.02%	1.78%	0.01%	0.18%	0.01%	0.07%	0.07%	0.01%	0.69%	1.10%	1.04%	0.05%	0.02%
24	Embedded DSM - (MWh)	100.00%	40.57%	8.16%	0.02%	14.17%	0.17%	8.52%	0.71%	3.93%	10.54%	11.13%	1.90%	0.17%	0.08%	0.08%	0.01%
25	Regulatory & Franchise - (Total Operating Revenues)	100.00%	55.18%	11.25%	0.03%	11.25%	0.12%	5.48%	0.45%	2.66%	5.63%	4.54%	3.01%	0.40%	0.36%	0.05%	0.01%
26																	
27																	
28	Functionalized Class Revenue Requirement - (Target)																
29	Generation	$744,404	$354,206	$60,621	$153	$101,469	$1,180	$57,481	$4,886	$25,885	$64,012	$62,043	$12,268	$199	$91	$99	$10
30	Transmission	$179,693	$87,806	$14,609	$36	$24,277	$281	$13,585	$1,164	$6,085	$14,821	$14,157	$2,872	$0	$0	$0	$0
31	Distribution	364,324	$232,110	$55,514	$48	$32,043	$201	$10,829	$736	$6,572	$8,133	$0	$17,928	$211	$196	$5	$9
32	Distribution-Lighting	$3,032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,032	$3,032	$0	$0
33	Distribution Total	367,356	$232,110	$55,514	$48	$32,043	$201	$10,829	$736	$6,572	$8,133	$0	$17,928	$3,243	$3,229	$5	$9
34	Ancillary Services	$23,675	$11,265	$1,928	$5	$3,227	$38	$1,828	$155	$823	$2,036	$1,973	$390	$6	$3	$3	$0
35	Customer - Billing	$15,079	$12,076	$2,298	$3	$329	$2	$24	$2	$24	$23	$2	$119	$177	$167	$8	$2
36	Customer - Metering	$21,031	$16,171	$2,777	$174	$824	$105	$173	$80	$26	$135	$207	$356	$3	$0	$0	$3
37	Customer - Other	$9,224	$7,664	$1,197	$2	$164	$1	$17	$1	$6	$6	$1	$63	$102	$96	$4	$1
38	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	Franchise Fees	$32,642	$18,012	$3,674	$9	$3,672	$38	$1,790	$147	$869	$1,838	$1,481	$981	$132	$116	$17	$2
40	Total	$1,393,104	$739,311	$142,617	$429	$166,005	$1,845	$85,726	$7,172	$40,291	$91,005	$79,864	$34,977	$3,862	$3,701	$136	$29
41																	
42	Ratio of Operating Revn to Revenue Requirement-(Target)	88.88%	80.76%	87.02%	77.38%	97.38%	112.10%	101.45%	100.83%	101.71%	105.52%	109.43%	83.47%	133.37%	119.22%	482.28%	285.28%
43	(Line 1 / Line 40)																
44																	
45	Increase or (Decrease)	$154,929	$142,248	$18,511	$97	$4,342	($223)	($1,239)	($60)	($687)	($5,022)	($7,531)	$5,783	($1,289)	($711)	($521)	($53)
46	(Line 40 - Line 1)																
47																	
48																	
49	Percent Increase (Decrease)	12.51%	23.82%	14.92%	29.23%	2.69%	-10.80%	-1.43%	-0.83%	-1.68%	-5.23%	-8.62%	19.81%	-25.02%	-16.12%	-79.27%	-64.95%
50	(Line 45 / Line 1)																

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost
December 2023 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		Schs 15, 51,
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, 54 (sec)
1	Units	Demand	Peak MW @ Input-System		1,152	92	100	0	73	108	138	4	30	148	15	75	70	5	125	186	38	
2	Units	Demand	Peak MW @ Input-Distribution		1,373	91	101	0	72	106	136	3	30	148	14	76	71	5	128	-	67	
3	Units	Demand	Peak MW @ Input-Transformer		3,702	455	282	-	292	482	379	-	69	259	-	130	-	9	-	-	229	
4																						
5	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558	
6																						
7	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356	
8	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997	
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	$258.90	
12	$/Unit	Demand	Transmission ($/System Peak kW)		$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$17.12	$26.11	$26.11	$26.11	$17.30	$17.30	$17.30	$17.30	$12.53	$12.53	$12.53	$26.73	$26.73	$0.86	$0.96	$0.00	$50.59	
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$26.31	$34.90	$34.90	$34.90	$26.33	$26.33	$26.33	$26.33	$21.70	$21.70	$21.70	$34.78	$34.78	$1.67	$1.86	$0.00	$59.88	
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$0.00	$18.40	
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$0.00	$1.48	$0.00	$1.48	$0.00	$0.00	$1.48	
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	$0.00778	
19	$/Unit	Energy	Transmission Energy @ Input ($/kWh)		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$78.70	$124.24	$124.24	$124.24	$79.28	$79.28	$79.28	$79.28	$54.92	$54.92	$54.92	$125.82	$125.82	$0.00	$0.00	$0.00	$251.98	
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$39.08	$61.68	$61.68	$61.68	$39.37	$39.37	$39.37	$39.37	$27.27	$27.27	$27.27	$62.47	$62.47	$0.00	$0.00	$0.00	$125.12	
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$85.45	$172.10	$228.58	$0.00	$708.48	$805.13	$871.54	$0.00	$989.88	$992.99	$0.00	$992.99	$0.00	$992.99	$0.00	$0.00	$817.24	
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$75.76	$102.46	$198.46	$0.00	$205.20	$214.31	$415.31	$0.00	$415.15	$799.21	$0.00	$2,733.92	$0.00	$2,733.92	$0.00	$0.00	$0.00	
25	$/Unit	Customer	Meters ($/Customer)		$23.21	$24.69	$28.37	$1,164.18	$31.92	$34.16	$177.40	$1,164.18	$177.96	$178.19	$1,164.18	$215.74	$1,164.18	$215.74	$1,164.18	$19,889.86	$34.18	
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$30.35	$30.35	$30.35	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$290.78	$290.78	$290.78	$290.78	$290.78	$30.33	
28	$/Unit	Customer	Uncollectables ($/Customer)		$9.64	$2.49	$2.49	$2.49	$25.02	$25.02	$25.02	$25.02	$148.58	$148.58	$148.58	$696.73	$696.73	$696.73	$696.73	$696.73	$8.29	
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$9.26	$9.19	$9.19	$9.19	$10.20	$10.20	$10.20	$10.20	$14.74	$14.74	$14.74	$44.26	$44.26	$44.26	$44.26	$44.26	$9.40	
30																						
31																						
32	$000	Demand	Generation	$610,554	$298,344	$23,738	$25,898	$121	$18,853	$27,958	$35,678	$955	$7,725	$38,432	$3,954	$19,360	$18,015	$1,316	$32,344	$48,104	$9,758	$0
33	$000	Demand	Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165	$0
34	$000	Demand	Dist-Poles	$43,954	$23,495	$2,370	$2,643	$9	$1,252	$1,841	$2,351	$56	$377	$1,857	$180	$2,043	$1,894	$4	$123	$0	$3,383	$77
35	$000	Demand	Dist-Conductor	$64,852	$36,118	$3,168	$3,533	$12	$1,905	$2,800	$3,577	$85	$653	$3,215	$312	$2,658	$2,464	$9	$238	$0	$4,004	$103
36	$000	Demand	Dist-Substations	$44,587	$25,258	$1,670	$1,863	$6	$1,331	$1,957	$2,500	$59	$554	$2,726	$264	$1,406	$1,304	$96	$2,363	$0	$1,230	$0
37	$000	Demand	Dist-Transformers	$9,372	$5,495	$675	$419	$0	$434	$716	$562	$0	$102	$385	$0	$192	$0	$13	$0	$0	$341	$37
38	$000	Demand	Total Demand	$783,647	$393,756	$32,022	$34,794	$151	$24,093	$35,745	$45,271	$1,170	$9,541	$47,265	$4,777	$25,986	$23,981	$1,461	$35,615	$48,917	$18,882	$218
39																						
40	$000	Energy	Generation	$115,902	$47,323	$4,580	$4,943	$27	$3,672	$5,589	$7,273	$197	$1,606	$8,332	$814	$4,260	$4,136	$325	$7,973	$12,443	$2,214	$194
41	$000	Energy	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	$000	Energy	Total Energy	$115,902	$47,323	$4,580	$4,943	$27	$3,672	$5,589	$7,273	$197	$1,606	$8,332	$814	$4,260	$4,136	$325	$7,973	$12,443	$2,214	$194
43																						
44	$000	Customer	Dist-Poles	$55,496	$42,111	$8,672	$1,790	$14	$382	$282	$160	$5	$12	$29	$3	$12	$8	$0	$0	$0	$2,015	$0
45	$000	Customer	Dist-Conductor	$27,553	$20,908	$4,305	$889	$7	$190	$140	$79	$3	$6	$14	$1	$6	$4	$0	$0	$0	$1,001	$0
46	$000	Customer	Dist-Transformers	$76,429	$45,720	$12,013	$3,293	$0	$3,414	$2,868	$1,754	$0	$211	$527	$0	$91	$0	$1	$0	$0	$6,535	$0
47	$000	Customer	Dist-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326
48	$000	Customer	Dist-Service Drop	$53,903	$40,536	$7,153	$2,859	$0	$989	$763	$836	$0	$88	$424	$0	$252	$0	$3	$0	$0	$0	$0
49	$000	Customer	Meters	$16,150	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273	$2.52
50	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	$000	Customer	Billing & Collections	$16,770	$13,431	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132	$196
52	$000	Customer	Uncollectables	$5,914	$5,155	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$43	$1	$20	$6	$36	$0
53	$000	Customer	Customer Service / Other	$5,964	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41	$66
54	$000	Customer	Total Customer (Commitment & Billing)	$264,503	$185,235	$36,801	$9,846	$160	$5,468	$4,426	$3,326	$93	$397	$1,195	$77	$475	$145	$5	$61	$167	$10,034	$6,590
55																						
56																						
57			Total Revenue @ Full MC ($000)																			
58			Generation	$726,456	$345,666	$28,318	$30,841	$149	$22,525	$33,547	$42,951	$1,152	$9,331	$46,764	$4,768	$23,620	$22,151	$1,641	$40,317	$60,547	$11,972	$194
59			Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165	$0
60			Distribution	$376,144	$239,641	$40,026	$17,289	$49	$9,897	$11,368	$11,817	$207	$2,002	$9,178	$760	$6,659	$5,673	$126	$2,724	$0	$18,509	$218
61			Distribution-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326
62			Customer - Billing	$16,770	$13,431	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132	$196
63			Customer - Metering	$16,150	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273	$3
64			Customer - Other	$5,964	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41	$66
65			Total Revenue (less Uncollectables)	$1,158,139	$621,158	$73,229	$49,547	$339	$33,113	$45,672	$55,820	$1,458	$11,513	$56,713	$5,660	$30,657	$28,221	$1,790	$43,631	$61,522	$31,093	$7,002
66																						
67			Customer - Uncollectables	$5,914	$5,155	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$43	$1	$20	$6	$36	$0
68			Total Revenue	$1,164,053	$626,314	$73,403	$49,583	$339	$33,234	$45,761	$55,871	$1,460	$11,544	$56,792	$5,668	$30,721	$28,263	$1,791	$43,650	$61,528	$31,129	$7,002

Energy

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

	(A)	(B) =(A)/12	(C)	(D) =(C)/12	(E) =(D)-(B)	(F)	(G)	(H)	(J) =(G)+(I)	(K)	(L)	(M)	(N) =(F)+(J)+(M)	(O)	(P) =(N)*(O)
Calendar Year (12 Mo Ended Dec)	SCCT Fixed Costs ($/kW-yr)	SCCT Fixed Costs ($/kW-mo)	CCCT Fixed Costs ($/kW-yr)	CCCT Fixed Costs ($/kW-mo)	Capitalized Energy Cost ($/kW-mo)	Capitalized Energy Cost 44.0% CF ($/MWh)	Purchase Cost ($/MWh)	Variable Wind Cost ($/MMBtu)	Variable Avoided Energy Cost ($/MWh)	REC Price ($/REC)	Oregon RPS %	Cost of RPS Compliance ($/MWh)	Total Avoided Energy Cost ($/MWh)	Present Value Factors @ 7.21%	Present Value of Energy (Mills/kWh)
2023	259.57	21.63	118.36	9.86	3.34	10.40	0.00	-5.94	-5.94	0.00	20%	0.00	4.46	1.0000	4.46
2024	265.49	22.12	121.05	10.09	3.41	10.63	0.00	-6.03	-6.03	0.00	20%	0.00	4.60	0.9327	4.29
2025	271.54	22.63	123.81	10.32	3.49	10.87	0.00	-5.91	-5.91	0.00	20%	0.00	4.96	0.8700	4.32
2026	277.73	23.14	126.64	10.55	3.57	11.12	0.00	-6.22	-6.22	0.00	20%	0.00	4.90	0.8115	3.98
2027	284.06	23.67	129.53	10.79	3.65	11.38	0.00	-6.13	-6.13	0.00	27%	0.00	5.25	0.7569	3.97
2028	290.54	24.21	132.48	11.04	3.74	11.64	0.00	-6.05	-6.05	0.00	27%	0.00	5.59	0.7060	3.95
2029	297.16	24.76	135.50	11.29	3.82	11.90	0.00	-5.85	-5.85	0.00	27%	0.00	6.05	0.6585	3.99
2030	303.94	25.33	138.59	11.55	3.91	12.17	0.00	-5.69	-5.69	0.00	27%	0.00	6.48	0.6142	3.98
2031	310.87	25.91	141.74	11.81	4.00	12.45	0.00	-5.84	-5.84	0.00	27%	0.00	6.61	0.5729	3.79
2032	317.96	26.50	144.98	12.08	4.09	12.73	0.00	-5.90	-5.90	0.00	35%	0.00	6.83	0.5344	3.65
2033	325.21	27.10	148.28	12.36	4.18	13.02	0.00	2.70	2.70	0.00	35%	0.00	15.72	0.4985	7.84
2034	332.62	27.72	151.67	12.64	4.28	13.32	0.00	2.68	2.68	0.00	35%	0.00	16.00	0.4650	7.44
2035	340.20	28.35	155.12	12.93	4.38	13.63	0.00	2.67	2.67	0.00	35%	0.00	16.30	0.4337	7.07
2036	347.96	29.00	158.66	13.22	4.48	13.94	0.00	2.56	2.56	0.00	35%	0.00	16.50	0.4045	6.67
2037	355.89	29.66	162.28	13.52	4.58	14.26	0.00	2.62	2.62	0.00	45%	0.00	16.88	0.3773	6.37
2038	364.00	30.33	165.98	13.83	4.68	14.58	0.00	2.68	2.68	0.00	45%	0.00	17.26	0.3519	6.07
2039	372.30	31.03	169.76	14.15	4.79	14.91	0.00	2.74	2.74	0.00	45%	0.00	17.65	0.3282	5.79
2040	380.79	31.73	173.63	14.47	4.90	15.25	0.00	2.81	2.81	0.00	45%	0.00	18.06	0.3061	5.53
2041	389.47	32.46	177.59	14.80	5.01	15.60	0.00	2.87	2.87	0.00	45%	0.00	18.47	0.2855	5.27
2042	398.35	33.20	181.64	15.14	5.12	15.96	0.00	2.94	2.94	0.00	50%	0.00	18.90	0.2663	5.03

	Mills/kWh
2023 (1 Year)	4.46
2023 - 2027 (5 Year, Short Run)	
Sum of PV Costs @ 7.21%	21.02
Annual Cost of Energy @ 21.92%	4.61
2023 - 2032 (10 Year, Medium Run)	
Sum of PV Costs @ 7.21%	40.37
Annual Cost of Energy @ 12.24%	4.94
2023 - 2042 (20 Year, Long Run)	
Sum of PV Costs @ 7.21%	103.46
Annual Cost of Energy @ 7.52%	7.78

Capacity

PacifiCorp
Oregon Marginal Cost Study
Marginal Capacity Costs
Based on Avoided Capacity Costs

	(A)	(B)	(C)	(D)	(E)
			(A) x (B)	(A) / 0.440 / 8,760	(B) * (D)
Calendar Year (12 Mo Ended Dec)	Projected Capacity $/kW	Present Value Factors @ 7.21%	PV of Capacity $/kW	Capacity Mills/kWh	PV of Capacity Mills/kWh
2023	$259.57	1.0000	259.57	67.34	67.34
2024	$265.49	0.9327	247.62	68.88	64.24
2025	$271.54	0.8700	236.24	70.45	61.29
2026	$277.73	0.8115	225.38	72.06	58.48
2027	$284.06	0.7569	215.01	73.70	55.78
2028	$290.54	0.7060	205.12	75.38	53.22
2029	$297.16	0.6585	195.68	77.10	50.77
2030	$303.94	0.6142	186.68	78.86	48.44
2031	$310.87	0.5729	178.10	80.65	46.20
2032	$317.96	0.5344	169.92	82.49	44.08
2033	$325.21	0.4985	162.12	84.37	42.06
2034	$332.62	0.4650	154.67	86.30	40.13
2035	$340.20	0.4337	147.54	88.26	38.28
2036	$347.96	0.4045	140.75	90.28	36.52
2037	$355.89	0.3773	134.28	92.33	34.84
2038	$364.00	0.3519	128.09	94.44	33.23
2039	$372.30	0.3282	122.19	96.59	31.70
2040	$380.79	0.3061	116.56	98.79	30.24
2041	$389.47	0.2855	111.19	101.05	28.85
2042	$398.35	0.2663	106.08	103.35	27.52

	$/kW	Mills/kWh
2023 (1 Year)	259.57	67.34
2023 - 2027 (5 Year, Short Run)		
Sum of PV Costs @ 7.21%	1,183.82	307.13
Annual Cost of Capacity @ 21.92%	259.49	67.32
2023 - 2032 (10 Year, Medium Run)		
Sum of PV Costs @ 7.21%	2,119.32	549.84
Annual Cost of Capacity @ 12.24%	259.40	67.30
2023 - 2042 (20 Year, Long Run)		
Sum of PV Costs @ 7.21%	3,442.79	893.21
Annual Cost of Capacity @ 7.52%	258.90	67.17

Avoided Costs

PacifiCorp
Filed Marginal Generation Costs

	12 Months Ended December			12 Months Ended December	
Calendar Year	Avoided Firm Capacity Costs (Battery) ($/kW-yr)	Avoided Wyoming Wind Fixed Costs ($/kW-yr)	Variable O&M Tax Credit And Integration Cost ($/MWh)	Avoided Firm Capacity Costs ($/kW-yr)	Wyoming Wind Fixed Cost ($/kW-yr)
2023	259.57	118.36	($5.94)	259.57	118.36
2024	265.49	121.05	(6.03)	265.49	121.05
2025	271.54	123.81	(5.91)	271.54	123.81
2026	277.73	126.64	(6.22)	277.73	126.64
2027	284.06	129.53	(6.13)	284.06	129.53
2028	290.54	132.48	(6.05)	290.54	132.48
2029	297.16	135.50	(5.85)	297.16	135.50
2030	303.94	138.59	(5.69)	303.94	138.59
2031	310.87	141.74	(5.84)	310.87	141.74
2032	317.96	144.98	(5.90)	317.96	144.98
2033	325.21	148.28	2.70	325.21	148.28
2034	332.62	151.67	2.68	332.62	151.67
2035	340.20	155.12	2.67	340.20	155.12
2036	347.96	158.66	2.56	347.96	158.66
2037	355.89	162.28	2.62	355.89	162.28
2038	364.00	165.98	2.68	364.00	165.98
2039	372.30	169.76	2.74	372.30	169.76
2040	380.79	173.63	2.81	380.79	173.63
2041	389.47	177.59	2.87	389.47	177.59
2042	398.35	181.64	2.94	398.35	181.64

WY Wind Capacity Factor	44.0%
Wind Heat Rate (Btu/kWh)	-
WY Wind Capa	30%

Fiscal Year:
Previous Year * 75%+Current Year * 25%
Calendar Year:
(Previous Year * 0%)+(Current Year * 100%)
Previous Yr = 0%
Current Yr = 100%